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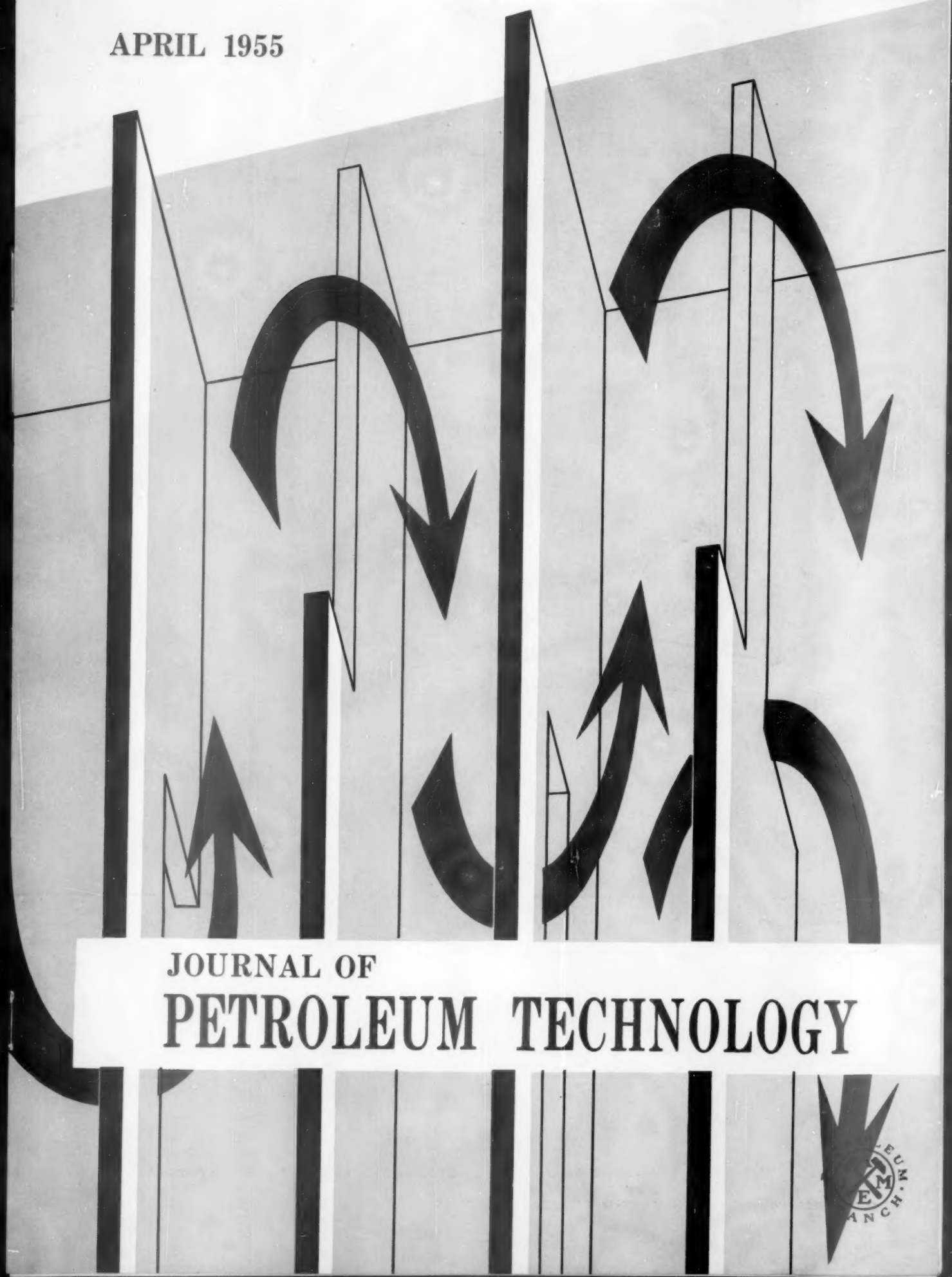

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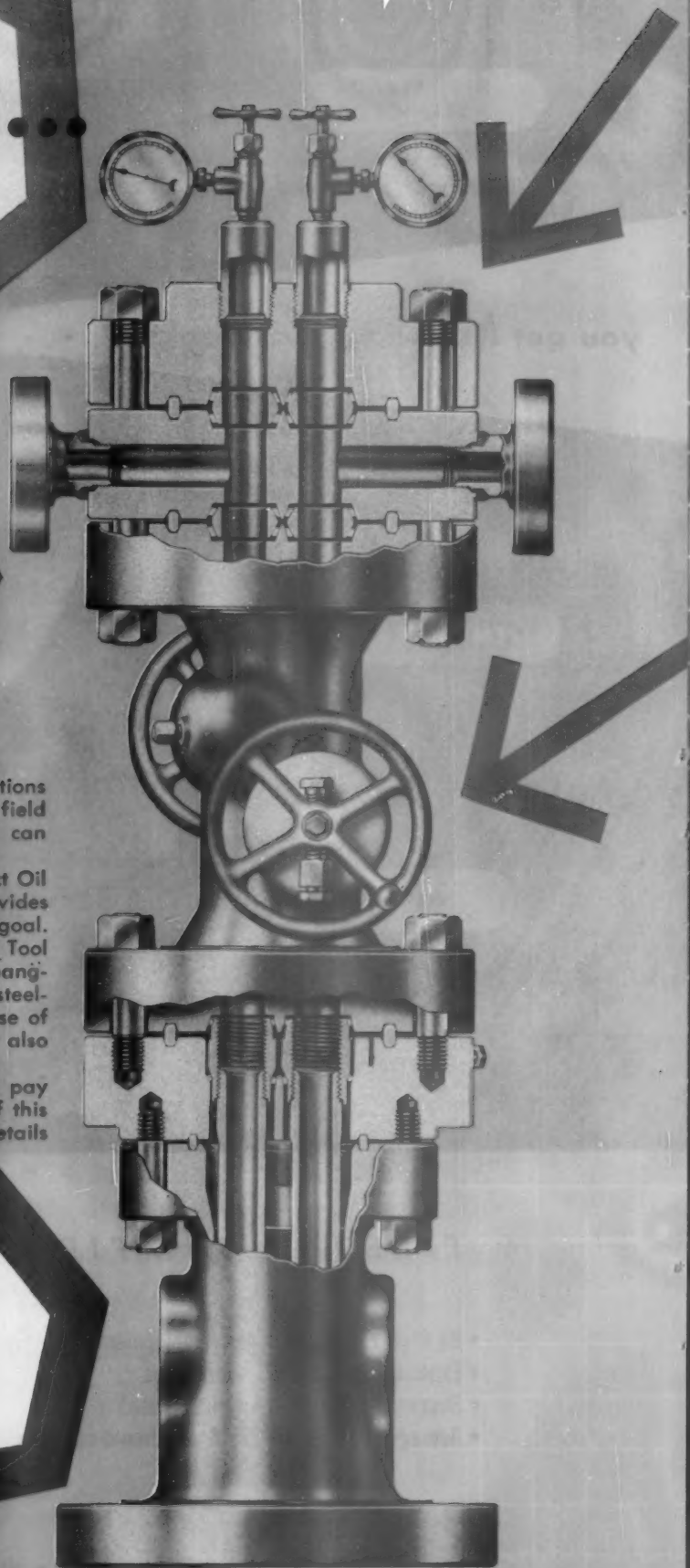

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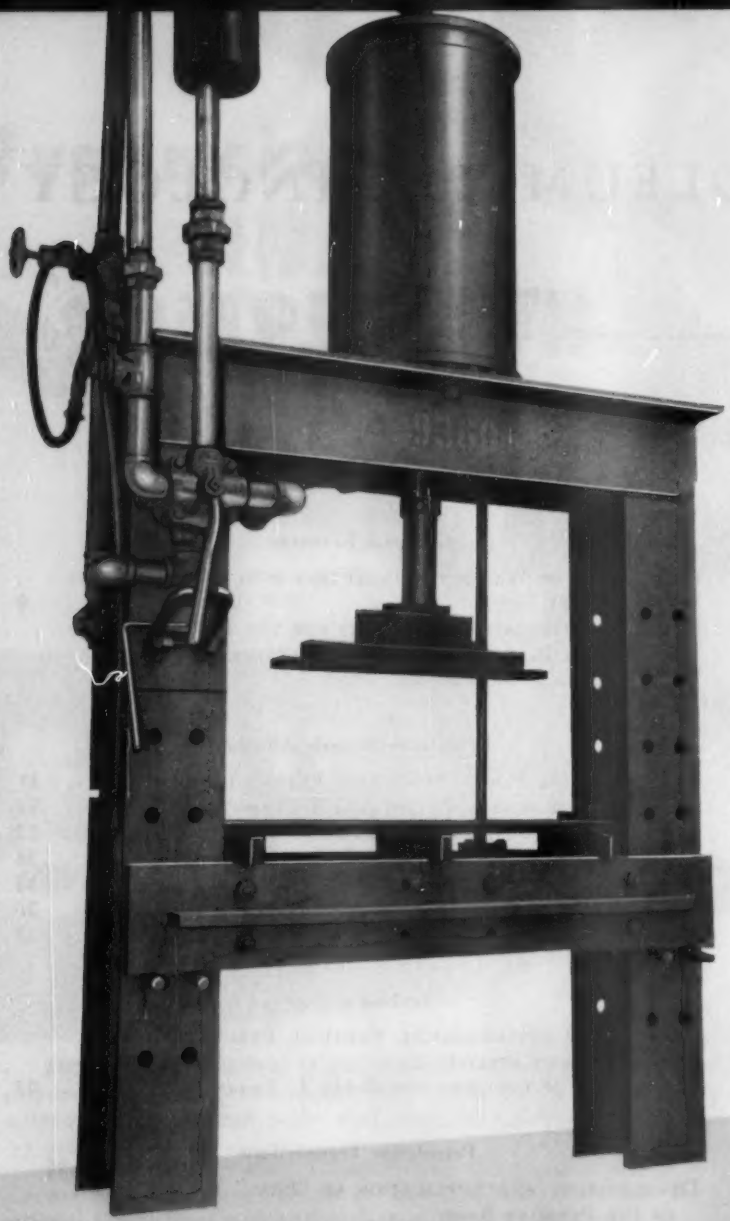

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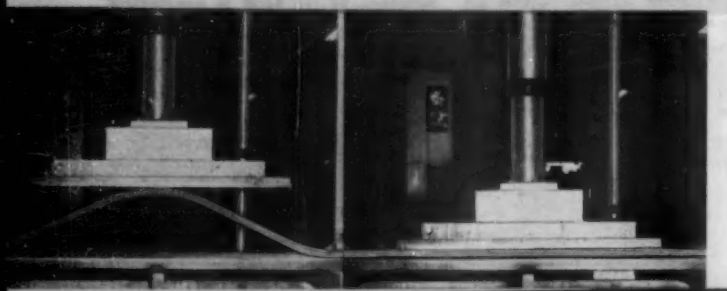

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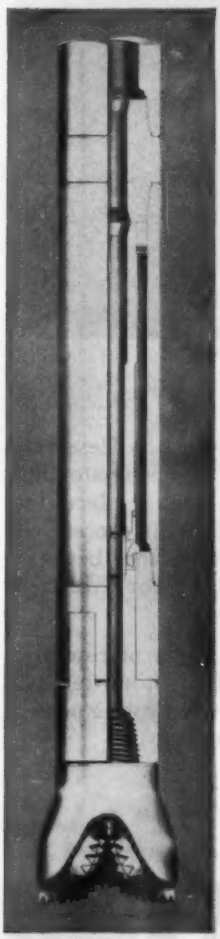

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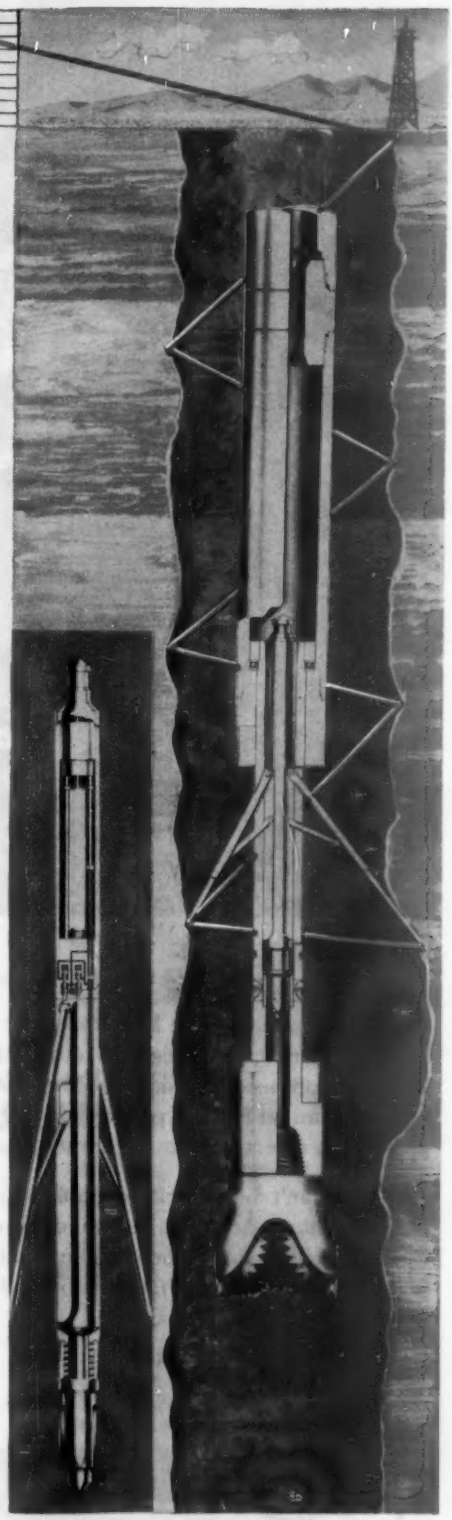

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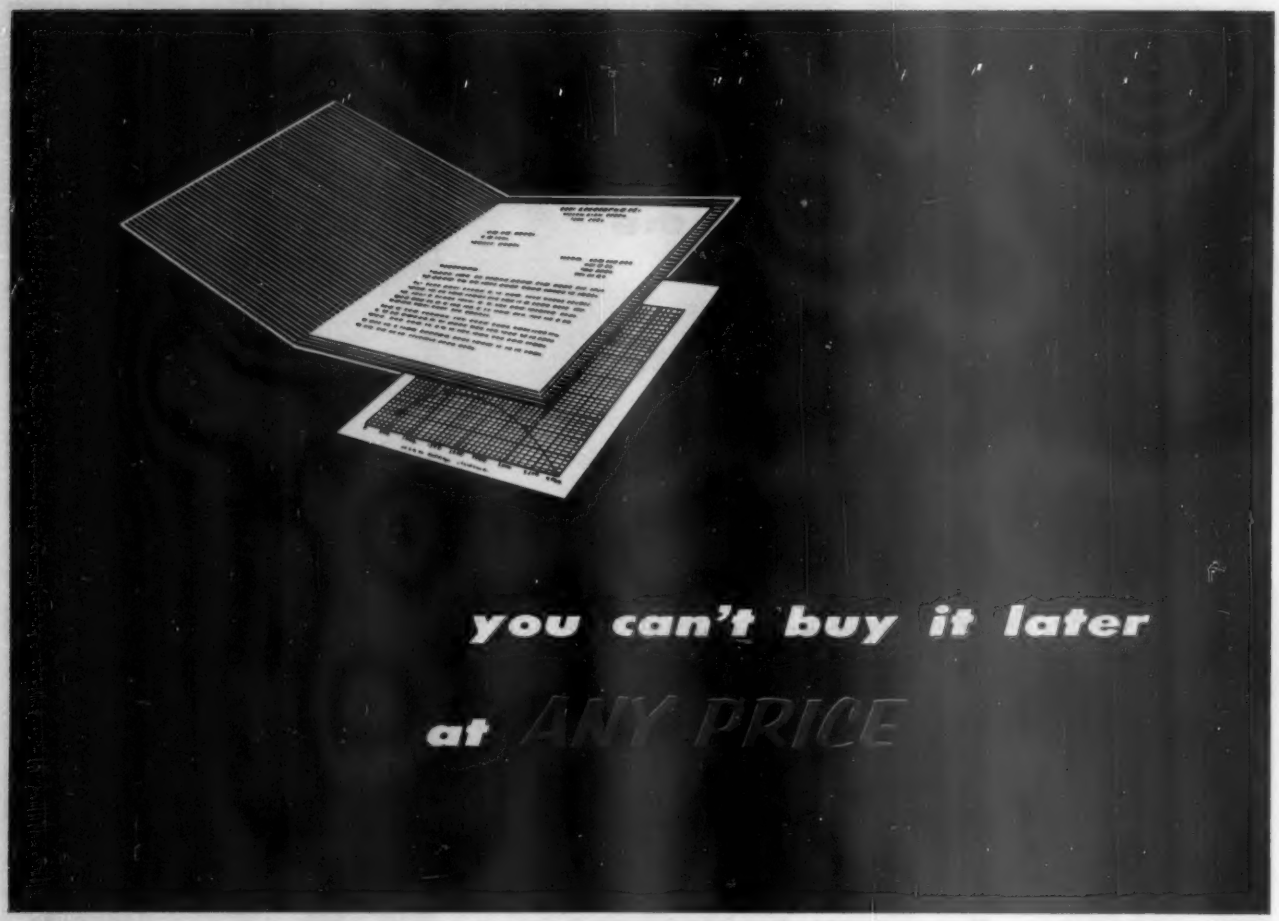

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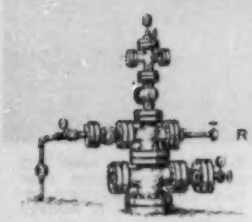

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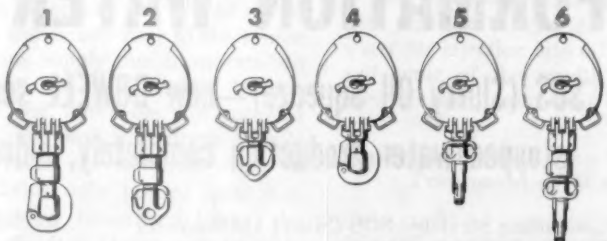

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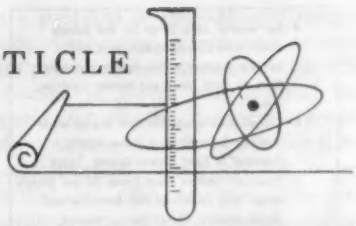

PREPARATION of WATER for INJECTION into OIL RESERVOIRS

PAUL DWIGHT TORREY
MEMBER AIME

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AUSTIN, TEX.

Introduction

The most important item in the injection of water into oil reservoirs is the water supply itself. Not only is a certain source of supply essential, but the quality of the water is also of great importance.

Nature rarely provides chemically pure or bacteria free water in any substantial quantities. Water, whatever its source, ordinarily contains a variety of impurities which may be inorganic, organic, or both. Even though these impurities may be present in very minute quantities, their existence must be recognized in almost every water injection system. However, the taste, the odor, or the toxicity of the water, important items where water is to be used for human consumption, are relatively unimportant in oil field use. The two principal problems connected with the use of water to improve oil recovery are possible reaction with the reservoir and its contents, and whether the water will cause destruction of surface and subsurface equipment by corrosion.

In the early days of secondary waterflooding operations in the Bradford and Allegany fields, little attention was given to the preparation of water, for an ample supply of fresh water of good quality was available from shallow aquifers and from surface streams. In the Southwest and particularly in Texas no such fortuitous conditions exist. In most parts of Texas, suffering as they have from recurring and progressively ruinous years of drouth, the oil industry will have little call on the limited supplies of fresh water, and therefore must resort to water resources of inferior quality. In almost every case such waters will require some form of treatment before they will be suitable for injection into oil reservoirs. Consequently, the importance of proper conditioning of water to be used for such purpose is now rather generally accepted.

The quantity of water that will be required for complete secondary recovery and pressure maintenance operations in the oil fields of Texas can be estimated in amounts of almost astronomical proportions. Studies recently completed by the Texas Petroleum Research Committee indicate some 10.5 billion bbl of oil that is physically recoverable by injection of water into the reservoirs. It is roughly estimated that approximately 15 billion bbl of water will be required for this purpose. The water that will be available for these operations will have to come largely from subsurface salt water-bearing formations and probably to some extent from the open sea.

Use of salt water from open or landlocked seas is, in principal, applicable whenever the site of an oil field is sufficiently near to the source of marine supply that transportation costs will not be excessive. Utilization of sea water has not received the consideration it deserves. In arid South Texas, for instance, where in many fields only limited quantities of salt water have been found, the nearby Gulf of Mexico would seem to be a ready solution to the problem of water supply. Just as cities have been forced to import water from far places for the maintenance of their population and industries, it is certain that the oil industry of the Southwest must begin to seek sources of unpreempted water, to investigate the most economical way in which such water can be transported from the point of origin to the point of use, and to devise methods of treatment that will make the water suitable for injection into particular reservoirs.

Actually, the problem of water supply, once it is concluded that salt water or otherwise contaminated water will have to be used, may not be as formidable in some fields as previous discussion might indicate, since sufficient salt water may be coming from the reservoir along with the oil production to initiate the recovery project. However, where little or no water is produced, a supplemental source of supply will be required. As the amount of produced water increases the need for the supplemental supply will diminish until most of the water required for the system will be produced water. Many times the necessity for the disposal of produced water to avoid the pollution of surface waters will justify its use instead of a supply from some different source even though the cost of treating produced water may be more expensive.

This paper will consider the materials that are being used to prepare water for injection into oil reservoirs, and some of the results that have been obtained from their use.

Materials Used for the Chemical Treatment of Water

As could be expected, a wide variety of materials is used for the treatment of water to be injected into oil reservoirs. Most of the inorganic compounds are well known and require little description. Some of the organic compounds are quite new; in fact, several of them have been applied successfully for the first time during 1954.

The way in which inorganic and organic chemicals are used for the treatment of water is considered in following parts of this paper.

The characteristics of surface-active agents have been described by

Paper given at Secondary Recovery Symposium presented by the North Texas Local Section of AIME and sponsored by the North Texas Oil and Gas Association, Nov. 17-18, 1954.

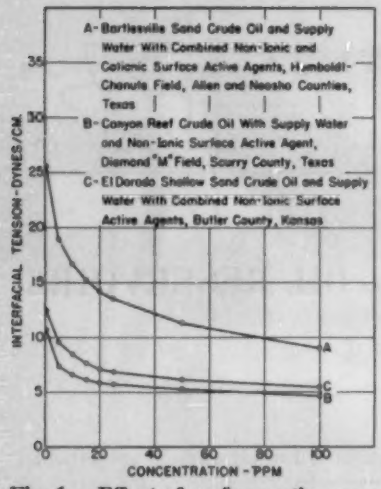

Fig. 1 — Effect of surface active compounds on reduction of interfacial tension between crude oil and supply water.

Dunning, Hsiao, and Johansen[1] and by Morgan, Prusick and Torrey[2] and reference is here made to their work. As reported by them, the greatest effect by surface-active agents on oil reservoir rocks is usually exhibited by compounds possessing limited solubility in water. In fact, some of the most effective compounds now known are soluble in water in concentrations below 200 ppm. Dunning et al[1] have presented interesting data on the relation between cloud point—the concentration of chemicals where true solution ends and dispersion commences — and the efficiency of displacement of oil by water.

Surface-active compounds derive their name from their ability, even in very low concentrations, to cause variations in the surface forces that exist between a liquid and another liquid, gases, or solids. Thus, the ability to reduce interfacial tension is a prominent characteristic of these materials. However, ability to reduce interfacial-tension between water and different crude oils varies widely, as shown in an accompanying illustration. These curves were selected specially for this purpose, and to show that the interfacial-tension between different crude and untreated water, also, varies in a wide range.

In Fig. 1 it will be seen that the interfacial-tension between crude oil and untreated water varies from 25.5 dynes/cm to 10.75 dynes/cm, and that the reduction in interfacial-tension by a 100 ppm solution of the most effective surface-active agents is from 14.5 dynes/cm to 6 dynes/cm. Projection of Curve B would indicate the possibility of such further reduction in interfacial tension that emulsification of the two liquids would take place. Variations in interfacial effects, as shown in these illustrations, may be attributed to natural polar compounds occurring in the crude oil and to differences in the viscosity of the oil.

The original work on the effects of surface-active agents on oil reservoir rocks at The University of Texas, which has been continued subsequently in a commercial laboratory, has shown that no single agent or group of agents would produce similar results in different reservoir systems, and that successful application of one agent in a particular system was no criterion of a similar measure of success in other systems, even reservoirs of the same geologic age and located in the same general area. At approximately the same time it was discovered that two or more surface-active agents, when combined, frequently gave much better results than one compound alone or the cumulative effects of several compounds, a relation which is referred to as synergetic behavior. From these discoveries, it was evident that specific treatments for indicated requirements would have to be developed in most cases for individual reservoir conditions, and that the compounding of basic chemical products for field use was essential. One important factor that influenced this conclusion is, as stated previously, that many of the most effective surface-active agents are sparingly soluble in water, and that their solubility is strongly affected by changes in temperature. Thus, by effective solubilization and by proper compounding of various combinations, the very best products can be formulated for particular needs and in such form that they can be used economically and efficiently under all weather conditions. The indiscriminate use of surface-active compounds in water treatment many times has resulted in failure.

Removal of Suspended Matter[3]

Most of the water available for injection into oil reservoirs contains suspended matter which must be removed to prevent formation plugging. If the supply water is allowed to remain stagnant for a considerable period of time most of the suspended matter will settle out and will accumulate at the bottom of the storage reservoir. However, this is a slow process and it requires large storage capacity. For this reason, the removal of suspended matter is usually accelerated by treatment of the water with a coagulating chemical. Aluminum sulfate (alum), $Al_2(SO_4)_3 \cdot 18\ H_2O$, is the most commonly used chemical for this purpose. Alum reacts with alkaline compounds in the water, such as calcium bicarbonate, to form a gelatinous precipitate of aluminium hydroxide according to the following equation:

$$Al_2(SO_4)_3 + 3Ca(HCO_3)_2 = 2Al(OH)_3 + 3CaSO_4 + 6CO_2$$

The aluminum hydroxide, as it is formed, entraps the particles of suspended matter by attaching itself to them, thus increasing their weight to an extent that they will settle from the water rapidly or can be removed from the water easily by filtration. The best coagulation in waters having a high saline content is obtained at a pH of from 5 to 8. The pH range through which alum is effective as a coagulant in brackish and fresh waters is more limited.

Prevention of Precipitation of Insoluble Compounds

Precipitation of insoluble compounds in water injection systems may take place either by the formation of carbonate and sulfate scale in the distribution system or on the face of the sand in the input wells, or it may result from reactions between compounds in the supply water with compounds in the water indigenous to the formation or with the formation itself.

The most common chemical treatment for prevention of formation of scale is the use of sodium hexametaphosphate, $(NaPO_3)_6$ or other complex phosphates, which is effective at a concentration range of from 2 to 10 ppm depending on the amount of scale-forming compounds in the water. Sodium hexametaphosphate provides good control over the precipitation of insoluble carbonates and sulfates even from supersaturated solutions, and over the precipitation of iron in small quantities. However, if the iron content of the water is high the polyphosphate is not as effective as certain of the new organic sequestering and chelating agents. Also, hexametaphosphate has one disadvantage in that it is not stable at high temperatures and will revert to orthophosphate with increase in temperature. The orthophosphate will react with lime compounds to form insoluble calcium orthophosphate which will have just as bad plugging

[1]References given at end of paper.

tendency as the scale-forming carbonates or sulfates.

Very recently, extremely effective organic sequestering and chelating agents have been tested successfully in the laboratory and in the field for prevention of scale formation. These compounds control undesirable precipitation of divalent and trivalent basic compounds by deionization. One of the best known of these organic compounds is ethylene diamine tetraacetic acid, which is completely stable up to temperatures of 150°C. It, and other similar compounds, will maintain iron, calcium, magnesium, and other basic ions in solution in a wide pH range of from 3.5 to 13.0. These agents are effective for the purpose indicated, after a fairly high initial treatment, in concentrations of as low as 1 quart per 1,000 bbl (about 6 ppm) of water so the convenience of their field use is combined with great economy. They should prove to be just as effective in producing oil wells where scaling conditions are severe as they are for the treatment of water injection systems.

Incompatibility of water to be injected into an oil reservoir with the water indigenous to it is a problem of considerable importance in many fields. The problem of incompatibility has been discussed adequately and authoritatively by Headlee.[4] Only a few of his more important findings and conclusions will be reviewed herein.

Physical factors which may cause precipitation or solution of mineral salts are temperature, pressure, evaporation, and condensation. The solubility of most salts increases with increased temperature. Some salts decompose into less soluble compounds as the temperature rises. Gases, in general, become less soluble in liquids with increase in temperature, and the solubility of gases in liquids increases with increased pressure.

Precipitation due to chemical reaction between a foreign water and water indigenous to an oil reservoir can take place when the partial pressure of some of the gases in either of the waters is changed, when salts in two different waters react to form new compounds which may be slightly soluble or insoluble, when oxygen dissolved in the input water reacts with the reservoir rock, or when other components of the injected water react with the reservoir rock. Actually, only a few types of precipitates are likely to form because of the limited number of basic and acid radicals that occur naturally in water. The most commonly precipitated anions are: carbonates, sulfates, sulfides, and hydroxides.

The solubility of the bicarbonates in water is directly proportional to the amount of dissolved free carbon dioxide present, which in turn is directly proportional to the partial pressure of the carbon dioxide in solution. Thus, under a high partial pressure of carbon dioxide a significant quantity of bicarbonates can be held in solution. Reduction of this pressure will permit the release of carbon dioxide from solution and thereby will cause the precipitation of scale-forming compounds.

Most of the common occurring sulfate compounds, such as calcium sulfate, are much more soluble in strong solutions of chloride salts, such as NaCl, $MgCl_2$, etc., than they are in fresh water. Therefore, commingling fresh water with a strong brine, containing an appreciable concentration of the sulfate ion, may cause a spontaneous precipitation of calcium sulfate.

Insoluble iron sulfide is precipitated as the result of the reaction of iron with hydrogen sulfide, that occurs naturally in many underground waters and is also produced by sulfate-reducing bacteria.

The oxidation of soluble ferrous salts, particularly ferrous bicarbonate, to form insoluble ferric hydroxide is the most common precipitation of hydroxides in water injection systems.

From the preceding limited and purposely untechnical discussion of incompatibility between different waters, it will be noted that three of the four processes that have been considered result from some action of dissolved gases, namely: carbon dioxide, hydrogen sulfide, and oxygen. Essentially complete degasification of water as near to its point of origin as possible by application of vacuum can, therefore, serve to prevent in large part underground precipitation of scale-forming compounds, but the process is expensive.

Control of Growth of Micro-Organisms

In many water injection systems the control of growth of micro-organisms and the closely related problem of prevention of corrosion, resulting from the life metabolism of sulfate-reducing bacteria or from the treatment employed to destroy them, water, but they are particularly trou-

is a problem of considerable magnitude. One-celled plants and animals are prevalent in almost every oil field blesome in warm and tropical climates where the temperature environment is most favorable for their multiplication. Their growth is retarded by cold weather. The anaerobic types will flourish underground, so the effects of their growth and the by-products of their growth were not observed in the early water-flooding operations in the Bradford and Allegany fields until controlled water injection was first employed. At that time the presence of algae was recognized in supply water and when input wells were cleaned out and backflowed the removal of accumulated masses of organic matter and iron sulfide from the bottom of the holes, along with opaque water, proved the presence and activity of anaerobic bacteria. Much more serious problems of bacterial control have developed in other areas, particularly in the Southwest, where brines rich in sulfate ions are being injected into oil reservoirs.

The various micro-organisms that infest waters being returned to oil-bearing formations have been described in detail by Williams[5,6] and by Allred[7]. Among the forms discussed by these authors are: algae, sulfate-reducing bacteria, iron bacteria, and capsulated bacteria. All of these organisms tend to collect as large masses of slime which will clog an entire injection system and will plug effectively water input wells necessitating expensive shutdown for cleanout. Troubles resulting from the growth of algae and sulfate-reducing bacteria are more common in Texas than from the other forms.

Of all the micro-organisms, algae are the easiest to eliminate or to bring under control. Inorganic compounds, such as copper sulfate and chlorine are generally effective. Among organic compounds that have been used with general success are formaldehyde, amines, quaternary amines, and combinations of these compounds.

The control of growth of sulfate-reducing bacteria has proved to be much more difficult. These organisms are widely and abundantly distributed in nature, and they are the only forms that have the ability to reduce the sulfate ion to hydrogen sulfide, the presence of which in any water will cause the corrosion of iron and steel equipment. Since they require no oxygen for growth and multiplication and are tolerant

to great differences in environment, they are found in varying numbers in most subsurface waters, both fresh and salt. Notably enough, they cannot be destroyed by aeration. They are quite resistant to many bactericides, and once a water system becomes severely infected with them, an expensive treatment may have to be employed to clean up the system and thereafter to enable the establishment of effective bacteriostatic control.

Experience in the East Texas field has shown that as long as chlorine can maintain control over the growth of the sulfate-reducing bacteria it is, unquestionably, the least expensive bactericide that can be used, and this is particularly the case in that field where the gathering and distributing lines and the tubing in injection wells have been protected against corrosion. However, similar to the life cycle of many other one-celled organisms, the sulfate-reducing bacteria, in course of time, frequently will develop so rapidly that the normal residual concentration of chlorine will not inhibit their growth. Increasing chlorine concentrations to the point where some measure of control over bacterial growth is obtained will result in a corrosive water which will be destructive to unprotected steel equipment. When a virile strain of bacteria appear in the water and their multiplication cannot be controlled by chlorine, the best known means for reducing infection is by means of organic bactericides. East Texas Salt Water Disposal Co. has reported[8] that a concentration of 8 ppm of an organic bactericide would be beneficial for the treatment of salt water to be returned to the Woodbine sand reservoir.

Some of the most effective organic bactericides are combinations of cationic compounds with or without formaldehyde. These substances are, in addition, good corrosion inhibitors and, thus, one chemical treatment will accomplish two purposes. It is believed that the film-forming properties of the cationic organic bactericides is responsible for the formation of a chemical coating around the body of a bacterium which prevents its normal metabolism, thereby, preventing multiplication. Thus, the bacteria are not poisoned, as is the case when toxic bactericides are used. For this reason, over a period of almost three years of continuous test, no culture of sulfate-reducing bacteria from the East Texas field has developed tolerance to certain of the organic bactericides.

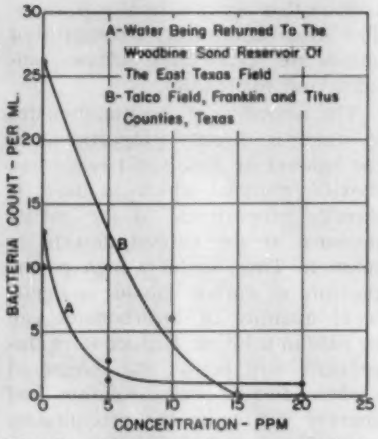

Fig. 2 — Results using organic bactericides for control of sulfate reducing bacteria in water being returned to the Woodbine Sand reservoir of the East Texas field and in produced water from the Talco field, Franklin and Titus counties, Tex.

Certain phenol derivatives are also effective bactericides, notably 2,3,4,6—tetrachlorophenol, sodium salt, but this and other like compounds can only be used with complete safety in relatively fresh water. Also, the phenol derivatives are sparingly soluble and consequently are difficult to handle in the field. They are very irritating to the skin and are quite painful to the eyes and respiratory passages. Thus, they must be handled with care to avoid prolonged contact with any part of the human body. They have no value for the protection of metals against corrosion.

The effectiveness of organic bactericides in the East Texas field and in the Talco field is shown in Fig. 2.

In the summer of 1951 competitive tests on the effectiveness of various organic bactericides were commenced in the East Texas field. At that time not more than 2,000 BWPD were contaminated with bacteria. In succeeding years the bacterial problem has become progressively worse, and at one time during the past summer (1954) it was estimated that 90,000 bbl of infected water were being produced each day, which amounts to about one-quarter of the water being returned to the Woodbine sand reservoir. The situation became so acute that the East Texas Salt Water Disposal Co. warned all operators connected to its system that it would have to discontinue accepting contaminated water.

There is good reason to believe that some of the water, presently being produced from wells in the East Texas field, has completed a full cycle of travel from producing wells to injection wells, then through the Woodbine sand reservoir, and now is being produced for the second time from wells located at higher structural position. The cycled water seems to be much more severely contaminated with bacteria than water produced for the first time from the Woodbine. Bacterial contamination began to be apparent in producing wells during the summer of 1954, as evidenced by the production of sour gas and by extraordinary corrosion of production equipment. The seriousness of this development will be immediately evident when it is understood that the equipment in producing wells is not protected against corrosion, such as is the case in the salt water gathering and injection system. Some form of down-the-hole chemical treatment, undoubtedly, will be required to protect equipment in wells when hydrogen sulfide gas makes its appearance along with ferric sulfide in the produced water.

In the East Texas field and elsewhere it is not considered necessary to obtain complete sterilization of the water. Such treatment would be so expensive that the cost would be greater than the benefits derived from the total elimination of micro-organisms. Thus a treatment sufficient to create a static condition in bacterial growth is considered to be adequate.

Protection of Equipment from Corrosion

Control of corrosion of metals is one of the most serious problems connected with the injection of water into oil reservoirs, particularly in cases where the water has a high saline content. In general, it will be found that high water salinity corresponds closely to a high corrosion rate. However, in addition to the salinity of the water, corrosion can result from dissolved gases in the water, such as oxygen, carbon dioxide and hydrogen sulfide—from the contact of different metals one with the other, and by high liquid velocities in the water distribution system.

Although attention in this paper is devoted principally to various forms of chemical treatment for the preparation of water, mention should be made that there are other methods, some of which have been quite successful under certain conditions, for the protection of equipment from

corrosion. Some of these methods are:

1. Exclusion of air from the gathering and injection system, and the removal of dissolved oxygen and other gases in open systems by application of vacuum.
2. The use of corrosion resistant alloys in place of ordinary carbon steel.
3. The use of nonmetallic substitutes for steel.
4. The use of protective coatings.

At the present time organic inhibitors have proved to be the most effective and the most economical method for the control of corrosion in many water-injection systems. This is particularly the case where a system is infected with bacteria, since some of the organic inhibitors are also lethal bactericides in low concentrations. One treatment, therefore, will provide control over microorganisms and at the same time protect the system against corrosion at low cost.

Combinations of cationic organic chemicals with or without formaldehyde have proved to be very effective water soluble inhibitors for some forms of corrosion in water-injection system. The ability of these compounds to inhibit corrosion is believed to be due to their absorption on metal surfaces. These inhibitors are effective in low concentrations, and certain of them are completely compatible with oilfield water so that their use will not cause plugging of the formation into which water is being injected. The organic inhibitors generally are not toxic to animals in the concentrations usually recommended. Therefore, danger from livestock poisoning, a serious and ever present problem in ranch country, is eliminated.

Other chemical inhibitors that have proved to be effective in some cases are formaldehyde and inorganic-acid salts which produce strongly oxidizing anions in relative dilute solutions. Chromates and nitrites are good examples of inorganic inhibitors, and they have been used quite widely where corrosion results from the action of organic acids. Their effectiveness is greatly retarded in the presence of hydrogen sulfide, and for that reason they are not applicable to many water injection systems. Nitrites and sulfites are effective for removal of dissolved oxygen in low concentrations in fresh waters only. These compounds are changed to nitrates and sulfates respectively by the addition of oxygen.

The chief objection to the use of chemical inhibitors is that they must be added to the water continuously or at fairly frequent intervals. If employees are not diligent in the use of inhibitors much damage to equipment may result before such negligence is discovered. However, mechanical feeders for continuous chemical treatment have been devoloped which require only occasional attention, and, in consequence, can be serviced by responsible engineers or production supervisors.

The manner in which an organic inhibitor and bactericide can protect a water-injection system is graphically shown in Fig. 3. In the operation from which results of corrosion control are shown in Fig. 3, the treatment is down the hole in the water supply well. As shown in the graph, Fig. 3, protection from corrosion has been progressively effective, as indicated by reduction in the iron content of the water, even at the low chemical concentration of 10 ppm. On July 29, 1954, the iron content of the water was less than 0.1 ppm.

Another example of effective use of an organic inhibitor for the protection of equipment against corrosion is illustrated in Fig. 4. The water being treated successfully in the Neosho County, Kan., water flood is obtained from the Mississippi lime and is very corrosive because of a high hydrogen sulfide content. Corrosion of steel equipment in contact with this water was severe, amounting, at the water supply well before chemical treatment was commenced, as shown by corrosion coupon test, to be 19.19 mpy $\left(\frac{19.19}{1,000}\right.$ in of penetration per year).

Treatment with an organic inhibitor was commenced on Jan. 1, 1953, with a slug of 4 gal of chemical per 1,000 bbl of water down the hole and 2 gal of chemical per 1,000 bbl of water after the filter for the first 24 hours of treatment.

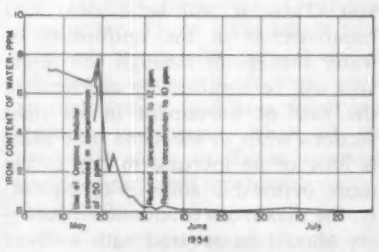

Fig. 3 — Control of corrosion using organic inhibitor in Grandfalls field, Ward County, Tex.

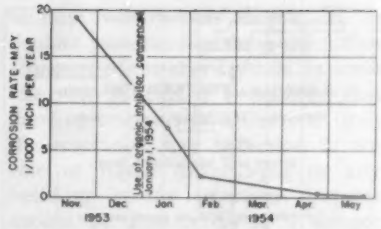

Fig. 4 — Use of organic inhibitor to control corrosion, Chanute field, Neosho County, Kan.

Thereafter, the treatment was reduced to 1.5 gal of chemical per 1,000 bbl of water down the hole in the supply well, with progressive improvement in corrosion control, determined by periodic coupon tests, as shown in Fig. 4.

Improvement of Reservoir Permeability to Water

Many oil fields in the United States produce from sands that occur at such shallow depths that it is not possible to inject water into them at an economic rate without danger from pressure-parting of the oil-bearing rock, even though it may possess favorable permeability characteristics. In other oil fields the permeability of the reservoirs is so low that similar difficulties are encountered, even though they may produce from greater depths. Any technique that will increase the permeability of the reservoir to water will accelerate the rate of depletion or will make possible the use of a wider, and, therefore less expensive, well-spacing pattern. Operating or development costs thereby will be reduced.

Several methods have been proposed for the acceleration of water injection rates, but in the field of chemical treatment the use of surface-active agents has proved to be the most successful when applied to reservoirs possessing hydrophobic tendencies.

Surface-active agents, as shown previously, will reduce the interfacial-tension, an easily measured quantity, that is developed when oil is brought in contact with water. Similarly, they will reduce the interfacial-tension between water and the surface of the reservoir, which is a value that cannot be measured directly because of the irregular surface of the pore openings. Indirectly, however, the resultant of the forces expressed as interfacial-tensions may be determined as capillary pressure, which is a measureable quantity. Reduction of interfacial-tension between a solid and a

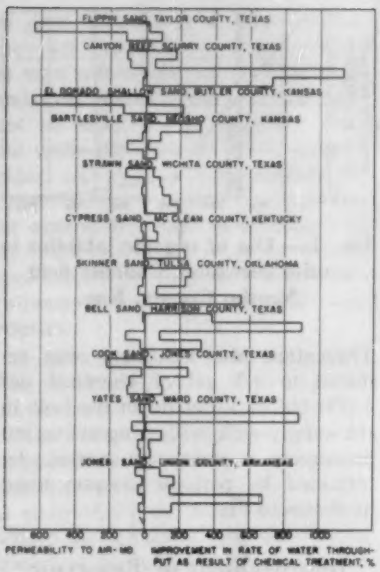
FLIPPIN SAND, TAYLOR COUNTY, TEXAS
CANYON REEF, SCURRY COUNTY, TEXAS
EL DORADO SHALLOW SAND, BUTLER COUNTY, KANSAS
BARTLESVILLE SAND, MCCOMB COUNTY, KANSAS
STRAWN SAND, WICHITA COUNTY, TEXAS
CYPRESS SAND, MC CLEAN COUNTY, KENTUCKY
SKINNER SAND, TULSA COUNTY, OKLAHOMA
BELL SAND, HARRISON COUNTY, TEXAS
COOK SAND, JONES COUNTY, TEXAS
YATES SAND, WARD COUNTY, TEXAS
JONES SAND, UNION COUNTY, ARKANSAS
600 400 200 0 200 400 600 800 1000
PERMEABILITY TO AIR- MD
IMPROVEMENT IN RATE OF WATER THROUGH-PUT AS RESULT OF CHEMICAL TREATMENT, %

Fig. 5 — Effect of surface active agents on rate of water through-put in reservoir rocks of variable permeability.

non-wetting liquid, consequently should serve to reduce capillary pressure.

Although capillary forces in oil reservoirs usually are not large, their effects are extremely important. Together with gravitational force, they control the original distribution of fluids in the reservoir, particularly the concentration of water. Because of their influence on the shape of the fluid interfaces within the pore system, they are responsible in part for the retention of oil in the reservoir.

It is well known that capillary pressure is a function of the principal radii of curvature of the interfaces, and such being the case, capillary pressure will be low in large openings and high in small openings. Thus, it has been found that relatively low capillary pressure exists in reservoir rocks having high permeability, and that relatively high capillary pressure exists in reservoir rocks having low permeability where permeability is controlled largely by the size of the pore openings.

Numerous laboratory flooding tests with dilute solutions of surface-active agents made at The University of Texas and in other laboratories, have demonstrated great acceleration in the rate of water through-put in tight core sections of various reservoir rocks and little increase in core sections possessing higher permeability. Results of some of these tests, which have been selected specially to illustrate this behavior, on reservoir rocks from Arkansas, Kansas, Kentucky, Oklahoma, and Texas are shown in Fig. 5.

From the data portrayed in Fig. 5, it can be seen that there is excellent relation between low permeability and large improvement in the rate of water through-put and between high permeability and little or no improvement in the rate of water through-put. Although it is emphasized that these relations do not prevail in every reservoir rock system, they have been found to hold in a sufficient number of cases to make their discovery a matter of considerable technical and practical importance. Furthermore, and of even greater importance, field experience is beginning to confirm these laboratory findings in applications where chemical treatment has been combase exchange, when a foreign water is brought in contact with the rock, is more responsible for the swelling of clay minerals than adsorption phenomena. Substitution of one ion by another ion could easily disturb a state of equilibrium that may have existed in the clay molecule for geologic periods of time, and could effect perceptibly the capacity of the clay to retain water.

Exchange of cations is influenced by the pH of the water being introduced into the oil reservoir. Acidic waters, with a high hydrogen ion concentration, will tend to shrink or flocculate the clay particles by replacement of basic elements of appreciable atomic weight by hydrogen, the lightest of all the elements.

Considerable difficulty may be experienced in trying to predict the swelling of clays brought about by base exchange, for it has been observed that the concentration of various cations as well as their position in the lyotropic series affects the exchange one for the other and vice versa. Probably, the best method for ascertaining the effect of base exchange is by means of laboratory menced simultaneously with the initial injection of water into a reservoir. Thus, it will be evident that improvement in the uniformity of water movement through the reservoir will be obtained by accelerating the rate of movement in its tight sections while at the same time there is little or no increase in rate in the more permeable zones. Consequently, the maximum economic oil recovery should be secured with a lower produced water-oil ratio than would be the case if most of the water moves much more rapidly through zones of higher permeability. Also, recovery should be obtained in a shorter period of time, and less water should be required for the flooding operation, a very important item in water deficient regions.

The results of the laboratory tests shown in Fig. 5 are also encouraging indications of the benefits in the way of increased injection rates that may be expected from chemical treatment of the water going into wells that have encountered a tighter than average reservoir condition. By increasing permeability to water in tight sand wells and without effecting the injection rate into more permeable reservoir sections, the movement of water can be balanced in the flood well pattern so that the accumulated oil bank will reach the producing wells from all directions at approximately the same time.

Results of the use of a non-ionic surface-active compound to improve water injection rates in three wells in the Reddin Unit field, Taylor County, Tex., are given in the following table and the injection behavior of one well is shown in Fig. 6.

It should be noted that chemical treatment of water was commenced in all three wells after substantial quantities of untreated water had been introduced into the Flippin sand reservoir through them. Thus, conditions were not nearly as favorable for successful chemical treatment as would have been the case if treatment had been commenced at the beginning of water injection. Little benefit was noted in the form of lower injection pressure or greater input volume immediately after the commencement of treatment, but there has been progressive improvement with time. It now appears certian that it will be possible to balance the water injection pattern, thereby promoting uniformity of water movement through the reservoir.

Laboratory flooding tests made by the Bureau of Mines[1], at the University of Texas[2], and by the Pennsylvania Grade Crude Oil Association[3] have shown that the recovery of oil can be improved to an appreciable extent by the use of surface-active agents. An example of the results of a typical laboratory flooding test is shown in Fig. 7. From this graph it will be seen that it was possible to reduce oil saturation by about 8 per cent of pore volume below the percentage recovered by the use of untreated water—a very appreciable amount—by flooding with a dilute solution of a combination of non-

ionic surface-active agents. Whether similar results can be obtained in the field remains to be demonstrated, although some evidence is developing at the present time that additional oil can be recovered from certain reservoirs.

It is recognized that many problems in connection with the use of surface-active agents remain to be solved. Also, there can be no disagreement with the conclusion that success can only be attained from their use where a profit is realized. Thus, if useful concentrations of the chemical cannot be maintained in solution due to loss by adsorption on the reservoir surface, it is doubtful whether great quantities of additional oil will be obtained by their use.

Control of Swelling of Bentonitic Clays in Oil Reservoir Rocks

The efficiency of many water injection projects has been reduced seriously and several outright failures have resulted from plugging of the reservoir rocks by swelling of clay minerals contained in them when the clays are brought in contact with water. This alteration may occur as a result of water adsorption phenomena or as a result of an exchange of basic radicals when foreign water is introduced into the formation. By either process, the volume of the contained clay may be increased substantially with resulting loss of formation permeability. The clays present in the oil-bearing formation, therefore, can have a profound influence on the flow of fluids and on the displacement of oil by water.

The structure of clays is characterized by thin platy particles that are sandwiched together like a deck of playing cards, and which is referred to frequently as the "lattice" structure. The individual particles have

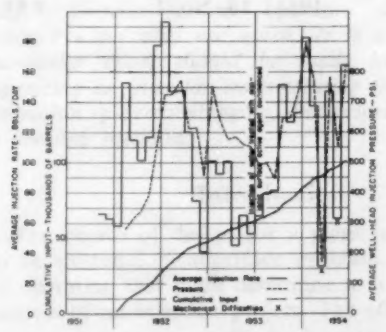

Fig. 6 — Water injection performance, Well No. 9-1C, Reddin Unit field, Taylor County, Tex.

TABLE 1—EFFECT OF SURFACE-ACTIVE AGENT ON WATER INPUT RATE, FLIPPIN SAND RESERVOIR, REDDIN UNIT FIELD, TAYLOR COUNTY, TEX.

Well	9-1C	14-7C	7-9C
6 Months Water Injection Prior to Chemical Treatment, Bbl	13,776	27,923	71,331
Average Wellhead Pressure, psi	609	542	458
Average Water Input Per Day, Bbl	76.1	130.5	387.7
Injectivity Index*	0.1250	0.2408	0.8465
6 Months Water Injection After Chemical Treatment was Commenced, Bbl	19,531	37,101	72,186**
Average Wellhead Pressure, psi	578	788	246
Average Water Input Per Day, Bbl	106.1	205.0	481.2
Injectivity Index*	0.1836	0.2601	1.9561
Current Injectivity Index***	0.1994	0.2904	3.3486

*B/D/psi
**Five Months
***Aug. 1, 1954

appreciable length and width but extremely small thickness. Because of this common dimensional characteristic, the clay particles tend to plaster themselves over surfaces as thin films rather than to accumulate as larger masses, and to separate and swell when they become wet with water. Montmorillonite, the predominate mineral in bentonite, has a highly developed lattice structure, and because of this characteristic it is possible for water to penetrate between the plates and cause pronounced swelling which may be sufficient to separate the plates and cause complete dispersion of the particle. A contributing factor is the negative polarity of the particles which causes them to tend to repel each other, and, further promotes dispersion. However, montmorillonite can take on many times its weight or volume of water before complete dispersion of the clay particles takes place.

For both siliceous and carbonate reservoirs, the degree of swelling of the contained clay minerals when they come in contact with water depends, first, on the type of clay, and, second, on the amount of water that the individual mineral may have held since the time of sedimentary deposition. Those clays which have taken on and held the maximum amount of water will not tend to increase in volume by adsorption when they are brought in contact with foreign water. Those clays which have retained a capacity for taking on additional water will do so if given an opportunity, and as a result will increase in volume. Most of the bentonitic clays in Texas reservoir rocks are deficient in water to a varying extent.

Swelling of clay particles may also take place as a result of an exchange of positively charged ions between an aqueous solution and the clay mineral with which they come in contact without disturbing the lattice structure of the clay crystals. In some reservoir systems it is believed that flooding tests on core material from the reservoir. Any reduction in the rate of liquid through-put or any build-up in the injection pressure should be considered as a danger signal and should cause consideration to be given to either a new source of water supply or to some form of chemical treatment that would prevent loss of permeability to water.

Up until a very recent time, the only way in which the swelling of bentonite in oil reservoirs could be controlled was by the use of highly acidic brines which inevitably created corrosion problems. A new and highly effective form of treatment for the control of swelling of bentonitic clays was discovered by J. H. Prusick in 1950. This method consists of a pretreatment of the formation surrounding a new water input well with sufficient hydrochloric acid to cause a radial penetration of from 4 to 5 ft from the wellbore. The acid is allowed to remain in the pores of the formation for several hours so that it may come in intimate contact with all clay minerals susceptible to swelling and thereby contract them to minimum size by hydrogen ion replacement. Immediately after the spent acid is retrieved the injection of water carrying very small quantities of non-ionic and cationic surface-active chemicals in solution is commenced. As shown by many laboratory flooding tests, cationic compounds are absorbed preferen-

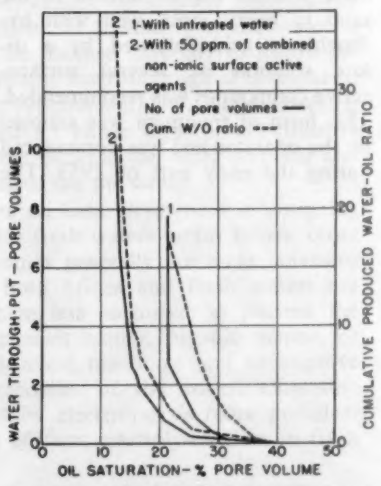
1-With untreated water
2-With 50 ppm. of combined non-ionic surface active agents
No. of pore volumes
Cum. W/O ratio
WATER THROUGH-PUT - PORE VOLUMES
CUMULATIVE PRODUCED WATER-OIL RATIO
OIL SATURATION - % PORE VOLUME

Fig. 7 — Results of laboratory flooding tests on core sample from El Dorado shallow sand, Butler County, Kan.

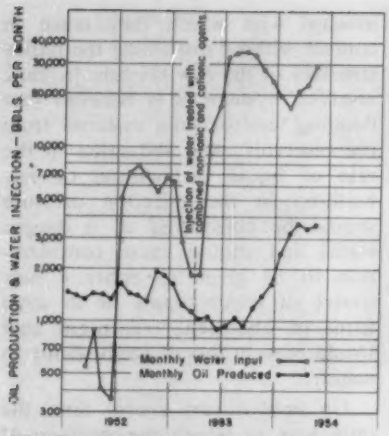

Fig. 8 — Monthly oil production and water input, Queen Sand water flood, Weiner-Colby field, Winkler County, Tex.

tially on the surfaces of the flocculated clay particles which serves to make them water repellent, or in simple terms, they are "waterproofed." In this condition they are not affected by water, and if the use of the surface-active agents is continued, a high degree of permeability to water can be maintained almost indefinitely. This form of treatment has been employed with a great degree of success in several fields for a sufficient period of time to demonstrate its effectiveness. A description of one application in the Weiner-Colby field, Winkler County, Tex., is given as follows:

Laboratory flooding tests on Queen sand core samples (Permian) from the Weiner-Colby field, Winkler County, Tex., indicated a "spotty" bentonite condition. As a result of these studies, a pretreatment of the sand in every input well with hydrochloric acid followed by a dilute solution of several surface-active compounds was recommended. This form of treatment was adopted by the operator and was commenced during the early part of 1953. The impressive results that have been obtained from this form of treatment are illustrated in Fig. 8. It can be seen from this graph that the rate of water input and of oil production has almost quadrupled since chemical treatment was initiated. It is believed that if the swelling of the clay minerals had not been controlled, the performance of this project would have been much less impressive. Also, it is considered probable, from records of unsuccessful untreated water injection experience in other parts of the field, that by the present time (July, 1954) this operation would be in a stagnant condition with greatly reduced water injection rates which would have a serious effect on the production of oil.

Conclusion

Original preparation of water to be injected into oil reservoirs in early flooding operations involved simple chemical treatment, such as the use of alum and lime. As application of methods to improve oil recovery have expanded from the eastern states the requirements for chemical treatment have increased to correct deficiencies existing in the inferior waters available for use by the oil industry, and to improve their qualities. The use of complex organic compounds to improve the effectiveness of water injection into oil reservoirs is a much more recent development. The performance of some of these compounds has been most promising, and recent evidence indicates interesting opportunities for their much more widespread use.

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DESIGN and OPERATION of PLANTS for the PREPARATION of WATER for INJECTION into OIL RESERVOIRS

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Abstract

Both the design of plants in which water is to be treated for subsurface injection and the operation of the plants are important to the success of waterflooding and pressure-maintenance operations. Treating plants should be designed specifically for conditioning of the water or brine to be used in the project. The principal factors to be considered in designing a plant are: (1) characteristics of water to be treated; (2) quality of treated water desired; (3) primary and ultimate capacity of plant; (4) most favorable location of plant site; and (5) type of plant and equipment that will best serve the purpose.

The operation of an injection-water-treating plant is at least as important as the proper design of the plant and judicious choice of treating methods. The important considerations in operating a plant are: (1) qualifications and training of operating personnel; (2) regularity and accuracy of water analyses; (3) analytical equipment and reagents used; and (4) precise control of mechanical equipment.

The design of equipment for the various steps in the treating process are discussed independently in this paper. Criteria for the optimum characteristics of treated water also are given. It is concluded that a particular effort should be made in designing and operating an injection-water-treating plant to minimize corrosion, prevent plugging, and improve the water as a flooding medium.

Introduction

The choice of design for a plant in which water is to be treated for subsurface injection and the method of operating that plant determine to a large extent the success of an injection project. The efficiency of water treatment and, consequently, the quality of the treated water, will depend directly upon the kind of equipment employed in the plant and the manner in which it is used, as well as upon the chemicals used for treatment. The factors involved in the design and operation of a plant for treating a particular water to the best advantage are discussed in this paper.

Generally, plants of simple design are better suited to the treatment of oil-field waters than are more elaborate ones, because the original cost of a simple-design plant is relatively low, and the maintenance and supervision are less than are required with a plant of more elaborate design. If a simple closed treating system is practicable, it is well to use one—both because of the lower original cost and because of the lower maintenance costs. However, some waters, because of their chemical composition, cannot be injected satisfactorily through a closed system. If treatment of the water is necessary, it should be planned carefully to insure the maximum financial return from the original investment.

The differences in requirements of a plant in which water is to be treated for either high- or low-pressure injection are negligible because the basic physical and chemical factors involved are the same.

Similarly, there are no basic differences in designing treating equipment for fresh waters or for brines, other than the fact that brines generally are more corrosive than fresh waters. Both brines and fresh waters are treated to render them less corrosive; to prevent the precipitation of suspended matter, organic matter, or solids formed by chemical reactions; and to improve the flooding characteristics of the water. Corrosion caused or intensified by electrolysis is more prevalent in brines, which are efficient electrolytes, than in fresh waters.

It also should be borne in mind that it is economically practicable, and solves salt-water disposal problems, to recycle water produced with oil. Usually such water contains dissolved solids in appreciable quan-

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tities. Consequently, even if a plant is designed to process only fresh water, it probably will be advisable to process brine in that plant in increasing quantity as the waterflood project progresses.

One additional fact to be remembered is that no matter how efficient are the design of the plant and the choice of treating chemicals, the plant will not run itself. It is necessary to analyze the water at frequent intervals and to use the results of these analyses as a basis for controlling the treating practices. Therefore, connections should be provided at key points in the treating and injection system where water samples may be obtained and corrosion specimens may be inserted if desirable.

Design of Treating Plant

The following factors should be considered and evaluated carefully in designing a plant in which water is to be treated for subsurface injection:

1. The characteristics of the water or waters to be treated in the system.
2. The quality of treated water needed to accomplish the desired objectives.
3. The primary and ultimate treating capacity required.
4. The optimum location of potential plant sites.
5. The type of plant that may be constructed and maintained most economically to provide the required water treatment.

Characteristics of Water

A careful evaluation of the water or waters to be handled should be made before any plans are developed for the construction of a water-conditioning plant or even before the type of plant is determined. Samples of water from the primary source and of water from the oil-productive formation should be analyzed. The possibility of using water from a third source as a standby supply also should be considered, and the characteristics of that water should be determined. An examination of the water should be made to detect the approximate quantities and types of micro-organisms present.

The effects of mixing the waters and the possible consequent formation of insoluble compounds that might tend to plug the sand, either at the wellbore or within the oil-bearing formation, should be considered. The possibility of corrosion caused by the various constituents of the waters should be given special attention. The compatibility of the waters may be determined either by hypothetical combination of ions of the waters as determined by chemical analyses or by actually mixing the waters, observing compounds formed and precipitated as a result of mixing, and then analyzing the precipitates. The former method is simpler and more reliable. The characteristics of the water supply available will be the major factor in determining whether a closed treating system may be used, either with or without filtration or chemical treatment, or whether it is more desirable to treat the water in an open system.

The quality of the raw water also will govern the chemical treatment that should be used with any type of treating system selected. Water having flooding characteristics rarely is available in the quantities needed for water flooding. Consequently, it seldom is possible to select a water for injection on the basis of an established treating plant. Instead, it usually is necessary to design the plant and treating methods to fit the water or waters available.

Quality of Treated Water

After the characteristics of the water available have been determined, the extent to which the water must be treated to achieve the quality of treated water desired must be considered in designing a treating plant.

The kind and quantity of dissolved gases are important factors. If both hydrogen sulfide and free carbon dioxide are present in appreciable quantities, it usually is necessary to remove those gases by aeration and chemical treatment. Water containing fairly high concentrations of free carbon dioxide, but no oxygen nor hydrogen sulfide, may be injected through closed systems with satisfactory results. However, two factors should be remembered in this connection. First, no water is completely noncorrosive to steel and the other metals commonly used for the fabrication of oil-field equipment, although some are much less corrosive than others. Torrey[1] cites projects in Pennsylvania and Canada in which the waters were so free of corrosive properties that the projects were operated for years with no damage to metallic equipment sufficient to necessitate replacement. Filtration and treatment to control micro-organisms were used on the Pennsylvania water and filtration and deaeration were employed with the Canadian water, but the corrosion in both instances was so slight that no corrosion inhibitors were needed. Also, it is difficult to keep any treating system completely closed from the atmosphere. If air is drawn into the system, the potential corrosivity of the free carbon dioxide will be intensified by the oxygen thus introduced.

Most surface waters that might be used for water injection are nearly saturated with air. Usually nothing is to be gained by injecting such waters through closed systems. Instead they should be treated in open systems to render them less corrosive and more stable and to control organic matter. In a few plants such waters are deaerated mechanically. In the treatment of many waters in either type of system, it is necessary to provide for the use of a reliable corrosion inhibitor because not all of the dissolved gases present may be economically removed by mechanical means.

Many waters contain suspended matter that must be removed by sedimentation and filtration. The suspended matter may include a variety of materials; one of the most troublesome is iron compounds, chiefly in the form of ferric hydroxide and ferrous sulfide. The presence of dissolved iron in appreciable quantity in the water should be considered in designing the treating plant. If it is high, there always is a possibility of insoluble ferric hydroxide being formed upon contact with air, as—for example—in a leaky "closed" system. Ferrous sulfide also may be formed if sulfides are present in the reservoir as a result of the action of sulfate-reducing bacteria.

If the raw water is highly supersaturated or is undersaturated with carbonates, it probably will be necessary to plan a treatment to stabilize the water. The treatment involves sedimentation and filtration—operations that can be carried out more easily in an open system than in a closed one.

[1]References given at end of paper.

Any ions present in two different waters that may cause the formation of insoluble compounds when the waters are mixed, either on the surface or underground, may require the use of treating equipment designed either to form and remove the insoluble compounds or to add sequestering or chelating agents that will prevent the precipitation of those compounds. For example, if a water containing an appreciable amount of soluble barium or strontium is mixed with a water containing excessive soluble sulfates, insoluble barium or strontium sulfate will be precepitated. This action may occur in the treating plant, within the distribution and injection system, or in the reservoir unless one ion is removed or sequestered before injection.

One of the principal causes of plugging of sand pores is the presence of micro-organisms in injection water. Algae, bacteria, and other organic matter introduced into or nourished in oil-productive formations may multiply rapidly until the sand face at water-input wells or the pores within the formation are partly plugged, thereby reducing water injectivity and consequent oil recovery. Anaerobic organisms thrive in the absence of oxygen, and many organisms may live in fresh water or in brine. Under many conditions plugging of the sand by organic matter is cumulative, and the operator does not realize that the organisms are present in the injection or connate water until plugging has occurred. If micro-organisms are present in any quantity, some provision for the addition of sterilizing agents to the water should be made when the plant is designed and constructed.

Some arbitrary standards of water quality may be established to aid in determining the capacity of the treating plant needed. The turbidity of the injected water should be less than 10 ppm. In the interest of minimizing corrosion, the following maximum concentrations of dissolved gases may be set: oxygen, 1 ppm; free carbon dioxide, 10 ppm; and hydrogen sulfide, 0 ppm.

The formation of a coating of ferrous sulfide on steel surfaces is one of the secondary effects of hydrogen sulfide reactions. This coating prevents deposition of a passive film, which is the basis of protection provided by many corrosion inhibitors. If unlined metal pipe is used in the treating and distribution system, the supersaturation of carbonates may be maintained at approximately 10 to 15 ppm, so that a thin, protective coating of calcium carbonate will be deposited on the surface of the pipe. A stable water is preferable if cement- or plastic-lined pipe is used. The content of soluble iron in the injection water should be less than 1 ppm; suspended iron should not be present.

Treating Capacity

Many waterflooding projects are started as pilot operations and often 10 to 80 acres are developed for flooding. If it becomes apparent that the pilot flood will be economically successful, the project is expanded at the end of the experimental period to include the total acreage available and suitable for flooding. It is economically impracticable to use full-scale treating equipment for the small quantity of injection water required in a pilot flood. However, unless the operator plans other pilot or small-scale operations at the end of the pilot stage of the original flood, small equipment sometimes becomes surplus at that time.

facilities is provided at the time the pilot-plant equipment is designed, the original equipment may be used in the expanded project by adding standard units as needed. The ultimate plant capacity should be considered in the original design of any treating plant. It is an economically sound practice to use the same filters, pumps, treaters, and other units throughout the life of a flood. Another important factor in designing a treating plant is that the ratio of produced brine to makeup water will increase as the flood progresses. If any facilities are provided especially for produced brine, such as skimming ponds, larger similar facilities will be needed as more brine is produced.

Location of Plant Site

If a plant is designed on a module basis and floor space or ground space adequate for the total anticipated

The first factors deserving consideration in choosing a site for a water-treating plant are adequate space and the proximity of both the primary water source and the disposal or injection points. The governing factor in selection of the plant site is likely to be the proximity of the main water supply, as the injection points usually will be fairly uniformly scattered throughout the flood property. However, a plant situated near the center of the flood area may be more economical because of a lower original cost and cheaper maintenance of piping.

The next important factor in selecting the site is the natural elevations of the land. A substantial saving in the original cost and in the operation and maintenance of the plant may be effected where the number of pumps can be minimized by gravitation of the water through the plant.

Type of Plant

After the characteristics of the waters to be treated have been determined, the quality of treated water desired has been decided, the capacity of the plant has been calculated, and a site has been chosen, the plant may be designed. As soon as the characteristics of the water have been determined, the decision may and probably will be made as to whether a closed. open, or semiclosed treating system is to be used.

Closed Systems

Closed systems may be defined as those in which the plant is designed to prevent contact of the water with the air, thereby avoiding oxidation-reduction reactions with consequent precipitation of solids formed by the reaction and subsequent solution of excess atmospheric oxygen in the water.

In the indirect closed system, which is widely used, water from the supply well is discharged into a water-storage tank having an oil seal on top of the water or natural gas in the vapor space above the water, as shown in the simplified isometric diagram in Fig. 1. The pressure of the water thereby is reduced to atmospheric, permitting part of the dissolved gases to escape. From the storage tank the water is pumped to the input wells by high-pressure pumps. Alkalies for pH control, coagulation, and sedimentation ordinarily are not used in closed systems because of the difficulty of isolating chemical treaters, mixers, and sedimentation ponds or tanks from the air. Filters sometimes are used and usually are the type employing interchangeable elements of silicon carbide or aluminum oxide. Sequestering, sterilizing, corrosion-inhibiting, and wetting agents may be added to the water satisfactorily in closed systems.

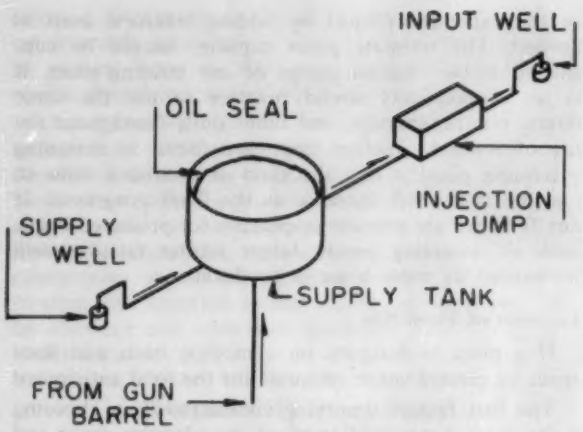

Fig. 1 — Simplified flow diagram of closed water-conditioning system.

The most important factor in designing a closed system is that, unless all tanks, pumps, treaters, and piping are leakproof, the primary advantage of using such a system is defeated. It is well to minimize the number of mechanical units and to keep the piping as simple as possible. All pipe connections must be made and kept tight.

Open Systems

No effort is made to exclude air from the plant in open systems. Instead, in most such plants the water is intentionally aerated to oxidize ferrous and manganous compounds to the insoluble ferric and manganic states and remove the dissolved acidic gases, thereby raising the pH value and reducing the carbonate supersaturation of the water. Fig. 2 is an isometric flow diagram of a typical open system. In this plant, the makeup water is aerated in a tray-type aerator and mixed with produced brine in an aeration and primary settling pond. The water then gravitates through a mixing chamber where treating chemicals are added by a proportioning feeder. The mixing chamber is set in the dike between a primary settling and a sedimentation pond equipped with baffles. The water gravitates from the sedimentation pond through filters into a clear-water tank, from which it is pumped to the input wells by a positive-displacement, high-pressure injection pump. The filters are backwashed by pumping water from the clear-water tank upward through the filter beds to a backwash pond.

Aeration

The capacity of aerators will vary with the type of aerator, the amount and efficiency of dissolved-gas removal, and the necessity for oxidation of ferrous iron and manganous manganese. Nordell[2] gives the capacities in gallons per minute of coke-tray and forced-draft aerators. These capacities vary from 10 gpm/sq ft for coke-tray aerators to 17.5 gpm/sq ft for forced-draft aerators. Nordell also presents an excellent discussion of the construction and efficiencies of various types of aerators for specific purposes. It is preferable to construct the aerator larger than indicated by available guides for conditioning brines that may contain dissolved iron, manganese, and acidic gases. Other things being equal, too much aeration is better than not enough. More efficient types of aerators include the combination forced-draft tray-aerator and the aerator in which air is dispersed beneath the surface of the water. The efficiency of the latter type depends upon proper dispersion of the air through numerous small orifices or diffusers to bring a maximum surface area of the water into contact with the air. One marked advantage of these two types of aerators is that the extent of aeration may be controlled by varying the speed of the blower or air pump. In this manner, if the original capacity of the aeration system is large enough, aeration may be maintained at a point where all of the hydrogen sulfide and most of the free carbon dioxide are removed and essentially all of the soluble iron and manganese are oxidized to higher valence states. This may be done without dissolving excess oxygen in the water and is an aeration practice that has been overlooked or neglected in the design and operation of many conditioning plants.

Chemical Treatment

The important factors in selecting or designing chemical treaters for a water-treating plant are as follows:

1. The feeder or feeders should be large enough to handle the chemicals at the maximum rates required.
2. Proportioning of chemicals in solution probably can be done more accurately than with dry chemicals; however, less space and labor are required for dry feeders.
3. Many water-treating chemicals are corrosive in concentrated form. Therefore, it is desirable where possible to employ noncorrodible or corrosion-resistant materials in chemical feeders and chemical-injection lines.
4. The feeder or feeders selected or constructed should have positive, easily regulated feed systems and should be as foolproof as possible.

Sedimentation

The proper design of sedimentation ponds or tanks is extremely important. The tank or pond should be so designed that ample detention time is provided to permit reaction-precipitated solids to coagulate and settle. Otherwise, the filters will be overloaded and will not operate at their designed theoretical efficiency. The use of combination treating and sedimentation tanks, such as Infilco Inc.'s "Accelator," is becoming more common in flood-water-conditioning plants. These units are efficiently designed to afford maximum removal of flocculated and coagulated solids with a minimum of

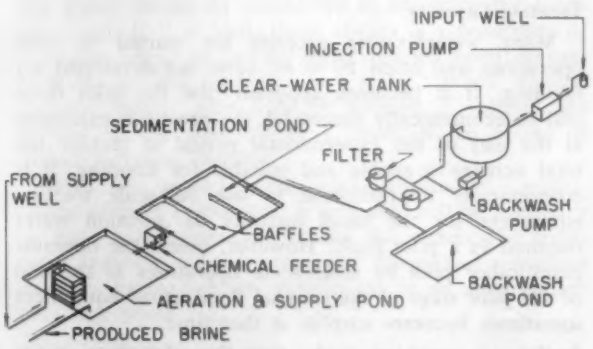

Fig. 2 — Simplified flow diagram of open water-conditioning system.

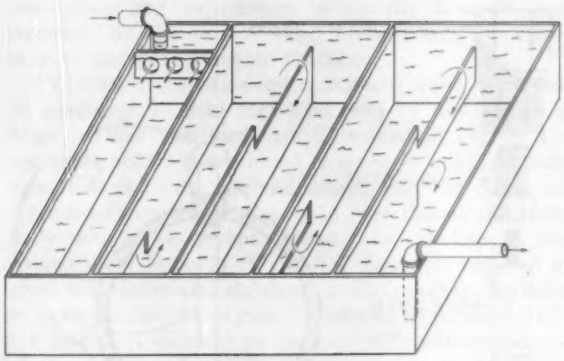

Fig. 3 — Sedimentation pond, showing arrangement of baffles.

water-storage space. However, it may be economically more practicable for the operator to design and construct sedimentation ponds if adequate space is available.

Two factors are important in the design of sedimentation ponds.

First, the permeability of the top soil in the vicinity of the plant should be determined. If the soil is permeable to water, it will be necessary to treat the walls and bottom of the pond with asphalt, concrete, or other impermeable material to prevent the loss of stored water.

Second, the importance of the judicious use of baffles in sedimentation ponds to increase the detention time of the treated water by assuring a uniform rate of movement of water through the pond cannot be overemphasized. In ponds without baffles, water moves in a stream directly from the inlet to the outlet. This not only does not permit enough time for proper coagulation and sedimentation but leaves the water at the sides of the pond stagnant, permitting the rapid growth of organic matter.

The use of "over-and-under" baffles in sedimentation ponds usually permits more uniform movement of the water through the pond than does the use of "end-around" baffles. However, a combination of the two types of baffles may be used to insure longer detention time and more uniform water movement. Fig. 3 demonstrates one manner in which combination baffles may be used. Such baffles may be constructed of wood, concrete, or concrete blocks. The small added expense in designing a sedimentation pond with adequate baffles will be repaid several times over in increased efficiency of plant operation. The size of the baffle openings may be calculated from the over-all size of the sedimentation pond and the daily throughput capacity of the plant. It should be remembered that the displacement time of a sedimentation pond or tank is calculated from the capacity of the pond or tank as compared to the quantity of water processed in the plant per unit time. The actual detention time often is much less than the displacement time.

Filtration

In designing or purchasing filters for a water-treating plant, several factors must be determined, as follows: (1) type of filter bed; (2) type of flow control; (3) capacities of filters; and (4) method and rate of backwash to be used.

Filters used to condition waters for subsurface injection are of two general types when classified as to the kind of filter medium, namely sand or anthracite filters and element-type filters. The most common type of filter used is the sand filter, in which fine sand is employed as the filter medium.

Element-type filters employ solid filtering elements of silicon carbide, aluminum oxide, or metal mesh fabricated in various shapes. The use of filters in which a slurry of diatomaceous earth forms a filter cake on a metal screen is becoming more common. Diatomaceous-earth filters are more efficient in removing bacteria and other organisms than are the conventional sand filters.

There are two general types of filter feeds, namely, pressure and gravity. Where the terrain permits, water may gravitate through the filters, and filters with open tops are most convenient. Where this is not possible, closed or pressure filters usually are employed and the unfiltered water is pumped through the filters under pressure. Both gravity and pressure filters most widely used today are the rapid type, in which the rate of filtration ranges from 2 to 4 gal of water per minute per square foot of filter area. The best filtration is obtained at or below the lower limits of this range.

It is far better to overdesign the filters as to capacity than to take chances on overloading them, which will result in a treated water of poor quality and will necessitate too frequent backwashing of the filters. Also, in most plants the quantity of water being processed through the plant daily will gradually increase. It is advisable to start with enough standard units of adequate size to allow for some increased rate of throughput that will permit use of the filters for some time before it is necessary to provide additional units.

The rate of backwash with unconsolidated filter mediums should be high enough to cleanse the filter medium by a scoring action of the sand grains in water and to regrade the filter medium by completely lifting and expanding the filter bed vertically. This rate varies from 10 to 25 gpm/sq ft of filter area. Somewhat lower backwash rates may be used with the less dense anthracite than with sand filters. The rates and quantities of backwash water needed with element-type filters normally are lower than those used with sand or anthracite filters. The quantity of water required for each backwashing will be from 1 to 5 per cent of the water filtered between backwashing operations.

Clear-Water Storage

The daily injection capacity of the plant will govern the type and capacity of clear-water storage needs. Treated water will be needed both for injection and for backwashing. It is advisable to have enough clear-water storage to permit operation of the injection system for several hours if any units of the treating plant must be shut down for repairs. A capacity equal to one-fourth to one-third of the daily injection capacity of the plant should be provided.

Semiclosed Systems

Semiclosed systems are those in which the water is treated in a conventional open system up to the point where dissolved gases are removed by mechanical means. From that point to the point of injection the

water is maintained in a closed system. Fig. 4 presents an isometric flow diagram of such a plant.

Deaeration

Vacuum deaeration usually is employed to remove oxygen that has been dissolved in the water during aeration or that was present in the water at its source. However, because of the cost of installing and maintaining vacuum deaeration systems the practice of deaerating water is not widespread. In fact, it has been discontinued in some plants originally equipped with vacuum deaeration systems.

Inasmuch as the maximum solubility of oxygen from air in most waters is less than 10 ppm and the solubility of free carbon dioxide and of hydrogen sulfide is much higher, the general practice of aerating waters to remove dissolved acidic gases is a sound one. The potential corrosivity of most waters containing dissolved free carbon dioxide and hydrogen sulfide is considerably greater than that of the waters after aeration.[3] If aeration can be controlled in the treating plant, as previously discussed, the quantity of dissolved oxygen in the water will be so low that deaeration will be unnecessary. Before designing a mechanical deaeration system for a treating plant, it is well to consider the cost of the system carefully as compared to the alternative cost of using a corrosion inhibitor if needed.

Operation of Treating Plant

The following factors should be considered in operating an injection-water-treating plant: (1) qualifications and training of personnel available for plant operation; (2) regularity with which water samples are obtained for analysis; (3) analytical apparatus and reagents available for field use; and (4) precise control of chemical treaters and other mechanical equipment in the plant.

Personnel

The most efficiently designed water-treating plant and the wisest choice of chemical-treating agents will not solve the problem of adequate water conditioning unless qualified and dependable plant operators are available. The cause of inadequate water conditioning in some plants may be traced directly to laxity on the part of plant operators rather than to basic errors in plant design or in the choice of treating methods. As the quality of injection water is one of the most important factors in a waterflooding project, plant operators should be

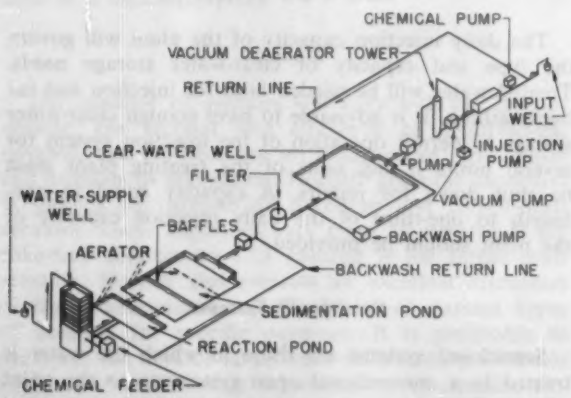

Fig. 4 — Simplified flow diagram of semi-closed water-conditioning system.

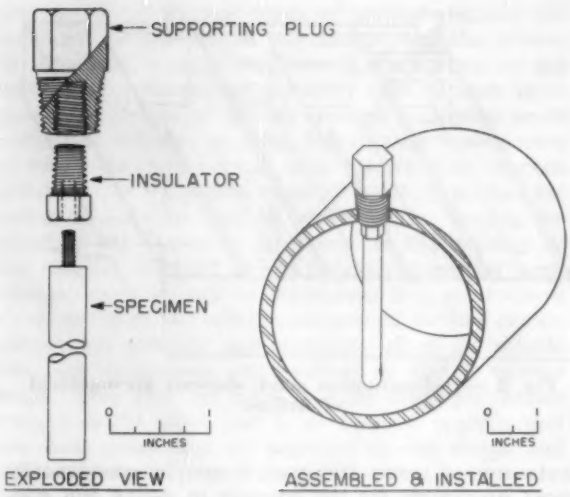

Fig. 5 — Field corrosion-test specimen.

selected from the more capable and conscientious employees of the company. Methods of water analysis accurate enough for control work[4,5,6] are simple enough that any capable and deft person may be easily trained in the analytical techniques. Judicious selection of plant operators will more than pay off in proper control of chemical treatment, maintenance of plant equipment, and improved quality of injection water.

Sampling

Frequent water analyses should be made, and rigid control should be practiced in most oil-field water-conditioning plants. The characteristics of waters, especially surface waters, are not constant but vary from time to time. This is especially noticeable when two or more waters are mixed in varying proportions. Mechanical treating devices do not proportion chemicals to water precisely and frequently need adjustment. The need for these changes can best be determined by analyzing the raw and treated waters. Samples for analysis should be obtained at selected key spots in the treating system. Analyses to determine pH value, alkalinity, and carbonate stability should be made at least daily, and determinations of dissolved oxygen, free carbon dioxide, and hydrogen sulfide should be made at regular but less frequent intervals, depending on the extent to which conditions vary. Total and dissolved iron should be determined occasionally. When steel pipe is used in the distribution system, it is well to make comparisons between the iron content of the water at the treating plant and at some of the input wells most distant from the plant, as the increase in iron content of the water is one indication of the amount of corrosion occurring in the system. If the water is chlorinated, daily residual-chlorine determinations should be made, so that the chlorine residual may be maintained at the desired level.

In the introduction to this paper, it was suggested that pipe fittings and valves be installed to provide for taking samples and making corrosion tests at selected locations in the treating and injection system. A ⅜-in connection will permit insertion of corrosion-test specimens when desirable. Corrosion-test specimens usually are of the flat coupon type and require 1½-in or 2-in openings for their use. The provision of large-diameter tees and plugs, in addition to the small (usually ¼-in) sampling taps needed may be considered an unnecessary

and unjustified expenditure when the plant is constructed. By the use of ⅜-in fittings, one connection may be made to serve both functions.

Cylindrical corrosion-test specimens have been used to advantage in field corrosion tests by the Bureau of Mines. These specimens are illustrated in Fig. 5. The specimen holder is machined from ⅝-in mild-steel hexagonal stock, with one end closed and the other end threaded externally with a ⅜-in pipe thread and internally with a ¼-in pipe thread. The insulator is machined from Hysol 6000 plastic, chosen because of its good machining and electrical insulating characteristics, with an external ¼-in pipe thread and an internal 10-32 NF thread. A shoulder on the externally unthreaded end of the insulator facilitates its connection to the holder and specimen and effectively insulates the two metal pieces. The corrosion-test specimen is machined from ⅜-in mild-steel rod with a 10-32 thread on one end.

Several lengths of corrosion-test specimens have been utilized. The total surface area of the specimen is made proportional to the cross-sectional area of the pipe in which the specimen is to be utilized. The specimens may be numbered by stamping the unthreaded end. Despite the apparent high ratio of the mass of the cylindrical-rod specimen to the total surface area, the total weights of the specimens range from about 33 gm for a specimen to be employed in 2-in pipe to about 67 gm for a specimen to be used in 6-in pipe. Therefore, the specimens may be weighed conveniently on an analytical balance. The surface areas of the specimens range from about 1.9 sq in for the 2-in pipe specimens to about 5.6 sq in for the 6-in pipe specimens.

Analytical Apparatus and Reagents

Many laboratory supply houses and some commercial analytical laboratories sell kits that contain the equipment and reagents necessary for field water analyses. In a large company, periodic checks of the accuracy of the tests performed by plant operators may be made by company engineers or chemists. Small companies may employ commercial analytical laboratories to recommend methods of treatment and analysis and to check periodically the results of tests by the plant operator.

Two alternatives are available to avoid the preparation and standardization of chemical reagents that may require skill beyond that available to the operator of a small water-conditioning plant. Reagents of the desired normality may be purchased directly from a commercial water-treating firm or a chemical-supply house. Or, if preferred, Acculute or Fixanal ampoules that contain the required quantity of chemical needed to make 1 liter of standard solution may be employed in the plant. In this manner, if solutions are used as rapidly or renewed as often as recommended, standardization seldom will be necessary.

Control of Equipment

The plant operator should be made thoroughly conversant with the significance of the various chemical tests and with the necessary adjustments to and care of mechanical equipment in the plant, as indicated by results of the analyses. Adjustments of chemical-feed devices should be made as precisely as the type of feeder permits. Control of the various physical steps in the treating plant, such as aeration, sedimentation, filtration, water storage, deaeration, and injection should be carefully practiced. There should be careful periodic inspections to detect evidences of the presence of organic matter, and the feed of sterilizing agents should be adjusted at once, if necessary. Corrosion-inhibition measures should be taken at the first indication of corrosion, such as iron pickup in injection water, leaks, or abnormally high turbidity of the water. Injection rates and pressures should be watched and controlled closely. Decreases in injection rates or increases in injection pressures may indicate gradual plugging of the sand face or sand pores in the reservoir.

Equipment in the treating plant should not be operated for any length of time significantly above rated capacities. Improved filter operation in open plants will result if proper coagulation and sedimentation are obtained before filtration. For this reason, it is recommended that detention times in sedimentation ponds and tanks be checked with fluorescent dyes. If inadequate detention time is indicated, baffles should be adjusted or additional baffles installed to permit more time for coagulation and sedimentation.

The use of "jar tests," in which measured portions of coagulants and alkalies are added to samples of the untreated water, will permit determination of optimum dosage rates of chemicals. Likewise, "screening" tests of sequestering agents, corrosion inhibitors, and sterilizing agents will yield approximations of the most effective additives for the particular water treated.

Finally, good housekeeping pays in water-plant operation as well as it does in other industrial operations. The best maintained plants will be found to be the safest, most efficient, and most economical to operate.

Conclusions

In general, it is concluded that a plant should be planned and operated specifically to treat to best advantage the water or waters that will be injected in the system. Moreover, close attention to the results of chemical analysis of the water and prompt and precise adjustments of mechanical equipment on the basis of those analytical results is a sound operating policy. Ideal water is seldom, if ever, available in the quantity needed for injection. Waters may be "overtreated" but not treated too well to render them in the best condition for injection. Although automatic controls are desirable, the system in general should be constructed and operated as simply as possible to accomplish the desired degree of water conditioning.

Acknowledgments

The author gratefully acknowledges the assistance of Paul D. Torrey, Orchem Corp., Austin, Tex., and D. B. Taliaferro and H. N. Dunning, Bureau of Mines, Bartlesville, Okla., in making helpful suggestions pertinent to this paper.

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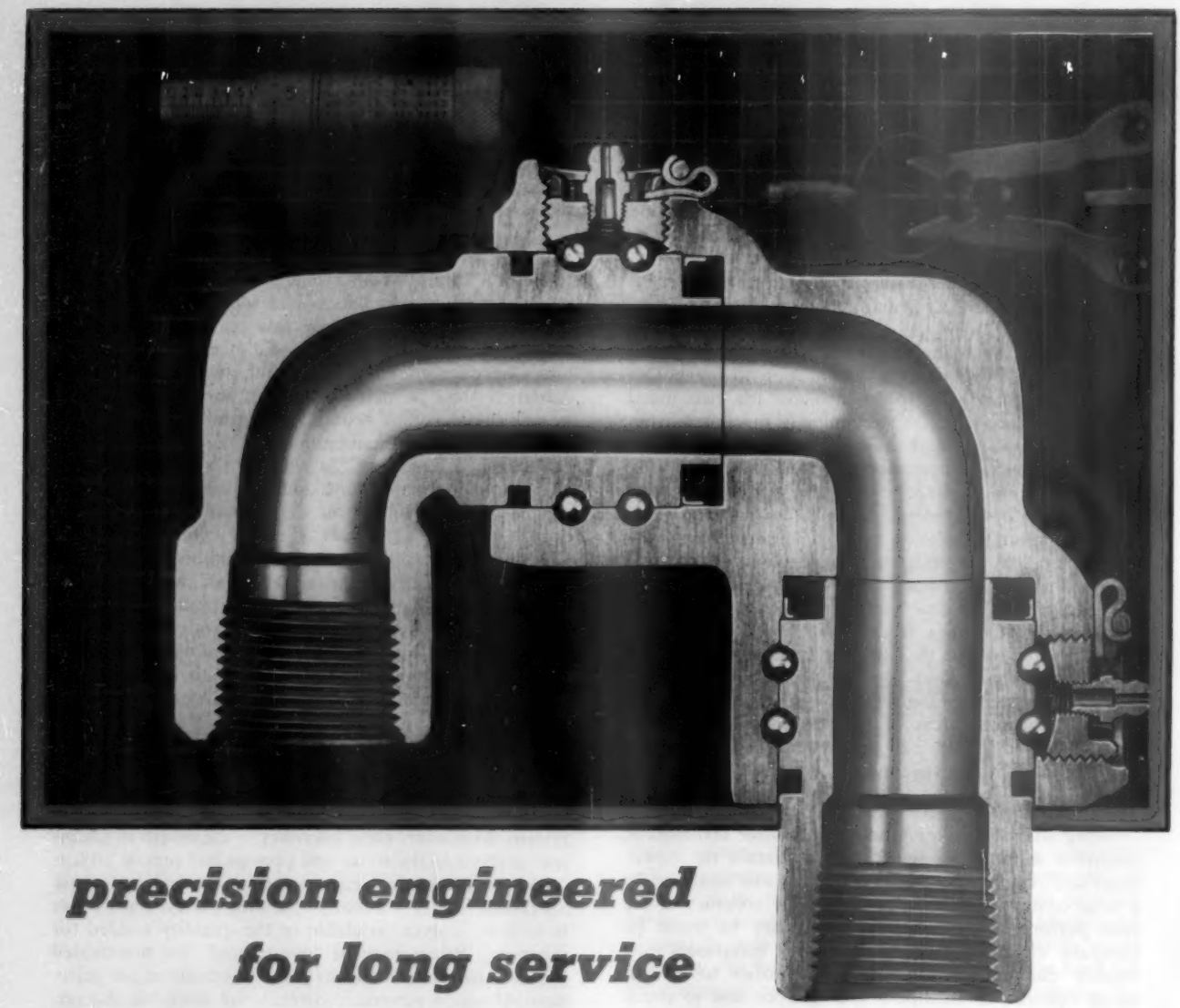

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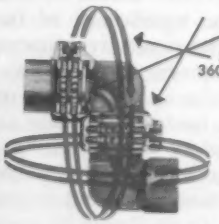

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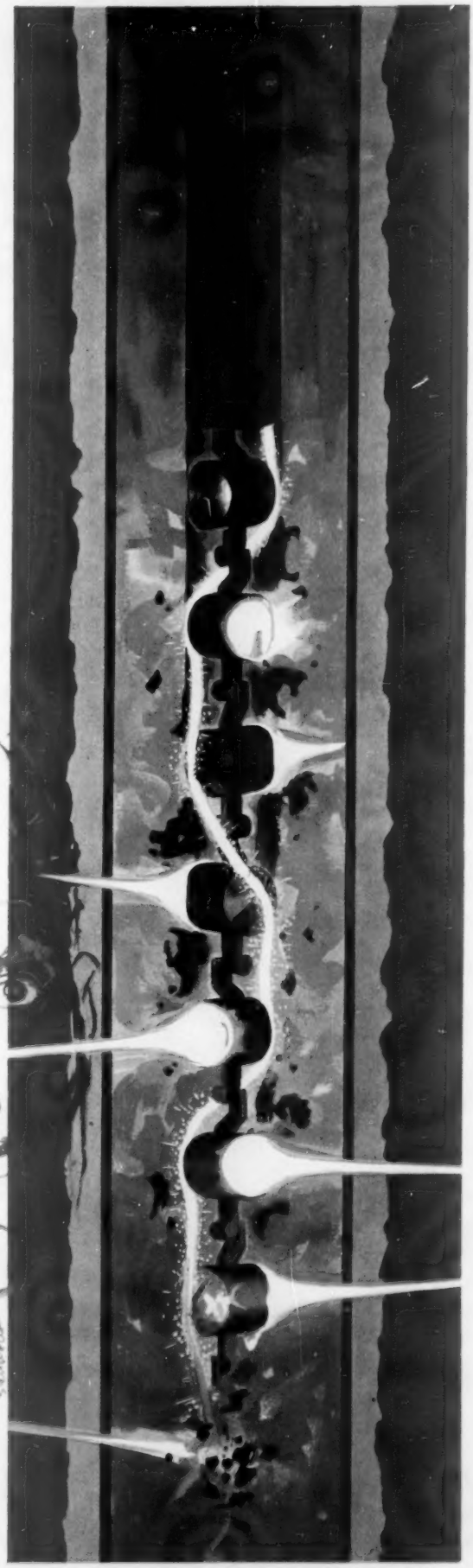

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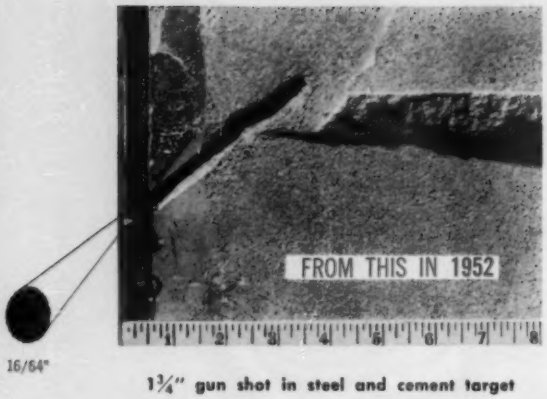
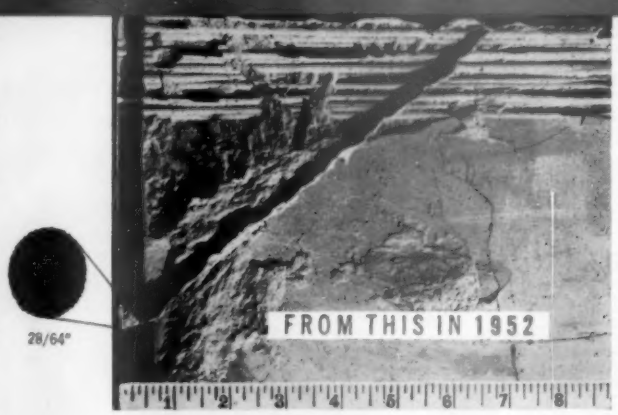


1¾" gun shot in steel and cement target



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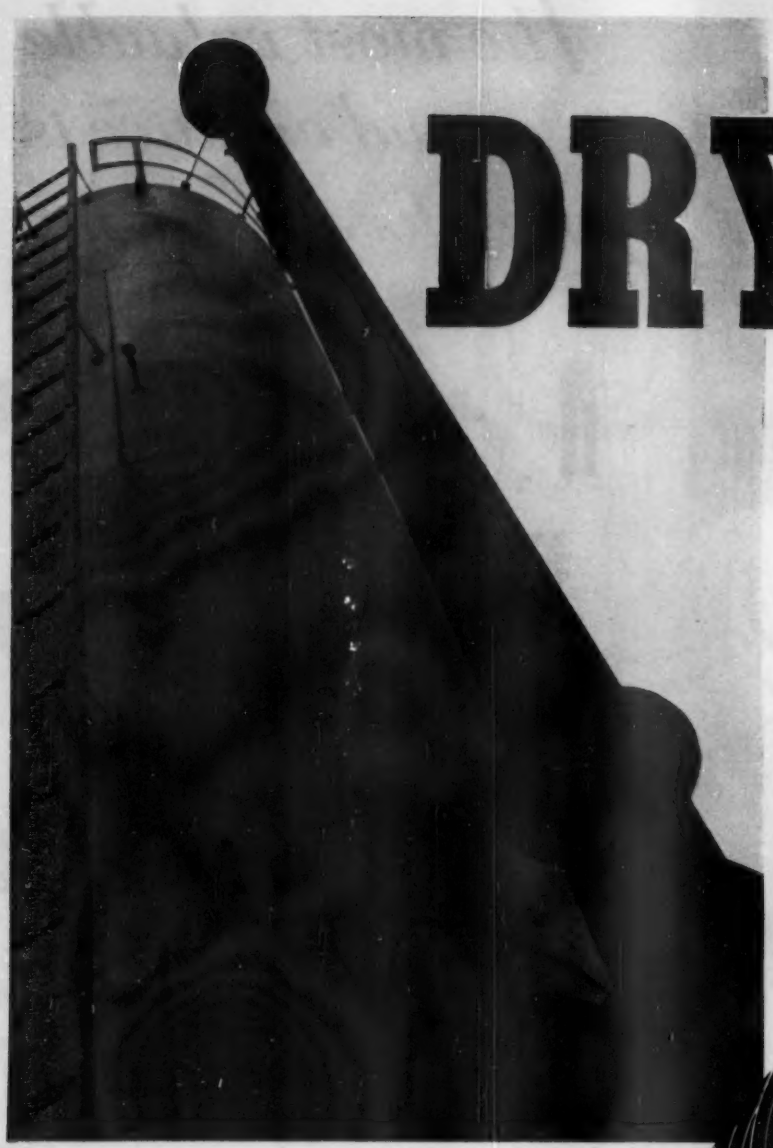

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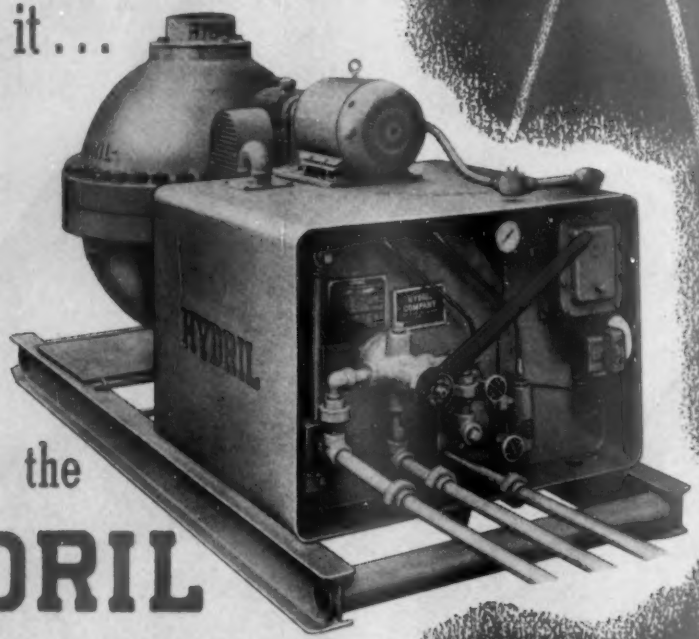

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May 26-27 in Denver

PROGRAM ANNOUNCED for JOINT MEETING of ROCKY MOUNTAIN SECTIONS

Ten technical papers are to be presented at the two-day Joint Meeting of Rocky Mountain Petroleum Sections in Denver. A welcoming luncheon and dinner-dance are also scheduled for this May 26-27 meeting at the Shirley-Savoy Hotel. The complete program is given below.

Rooms have been set aside at the Shirley-Savoy, Brown Palace, and Cosmopolitan Hotels for those who wish to attend. These rooms should be reserved directly through the hotels; not through the Housing Committee. All applications for accommodations should state that the person is coming to attend the AIME meeting.

Some 4,000 announcements for the meeting have been mailed, and a large attendance is anticipated. Housing Committee Chairman R. S. Cooke suggests that reservations be made early to ensure best accommodations.

R. L. Hoss, Vaughey & Vaughey, is general chairman of the meeting, and J. C. Johnston, Continental Oil Co., is honorary chairman. AIME sections sponsoring the joint meeting are the Denver, Casper, and Billings petroleum sections.

PROGRAM

Thursday, May 26

8:00 to 10:00 a.m.: Registration

10:00 a.m.: *A Gas Transmission Company Looks at the Rocky Mountains* by S. C. Barrett, Colorado Interstate Co. An analysis of the Rocky Mountain region as a source of supply and as a market for one of the country's oldest gas transmission companies.

11:00 a.m.: *Novel Features of Small Gasoline Plants* by J. J. Weatherby, Stearns-Rogers Manufacturing Co. A discussion of special problems of plants in the area caused by their smallness of size, the climate, and water.

12:00 m.: Welcoming Luncheon with the keynote speech by R. W. French, Jr., vice-president and general manager of Sohio Petroleum Co.

1:45 p.m.: *Big Muddy Field Flood, Wall Creek Sand* by R. W. Haller, Continental Oil Co. A summary of the reservoir studies and development program which has led to the doubling of production from Wall Creek in less than two years.

2:45 p.m.: *Complexity of Multiple Zone Reservoirs of the Dakota Formations in Western Nebraska, and Related Production and Development Problems* by P. L. Essley, Jr., Ohio Oil Co. An explanation of problems caused by sand lenses in first and third Dakota formations, which in many instances cause different fluid contacts, distinct pressure histories, and different type producing mechanisms.

3:45 p.m.: *The Effect of Clays on the Permeability of Reservoir Sands to Waters of Different Saline Contents* by Oren C. Baptist and S. A. Sweeney, U. S. Bureau of Mines. This paper presents a study of three Wyoming sands to determine the effects of clay on permeability to waters of different saline contents.

Friday, May 27

9:00 a.m.: *New Developments in Percussion Drilling* by Emory N. Kemler, University of Minnesota. A review of the current status of percussion drilling equipment is given, as well as a brief historical summary of its development.

10:00 a.m.: *Air and Gas Drilling* by C. L. Moore, El Paso Natural Gas Co. This paper presents such information on air and gas drilling as the history, gross required in drilling, advantages, disadvantages, and probable solution to disadvantages.

11:00 a.m.: *Spectrocounter Logging* by L. W. Toelke, McCullough Tool Co. The "Spectrometer," a tool which enables evaluation of the naturally radioactive elements as well as the effect of bombardment of non-radioactive elements with a radioactive source, is explained.

12:00 m.: Ladies' Luncheon and Entertainment.

1:45 p.m.: *Effect of Fluid Loss on Fracture Extension* by H. F. Coffer, Continental Oil Co. The paper shows how properly engineered fracture operations in which low fluid loss oils are used can succeed where other methods have resulted in sand-outs.

2:45 p.m.: *Electric Analog Interpretation of Drill Stem Test Pressure Build-up Curves* by Gilman A. Hill, Petroleum Research Corp. An explanation is made of newly-developed electric analog models which are effective for interpretation of bottom-hole pressure, fluid transmissibility, free volume compressibility, and wellbore damage.

6:30 p.m.: Social Hour

7:30 p.m.: Dinner-Dance

EXHIBITORS' GUIDE

Exhibitor	Booth Number
Baker Oil Tools, Inc.	4
Core Laboratories, Inc.	6
Dow, Inc.	11
Eastman Oil Well Survey Co.	7
Frontier Airlines	15
Halliburton Oil Well Cementing Co.	8
Johnston Testers, Inc.	2
Lane-Wells Co.	9
McCullough Tool Co.	3
McEvoy Co.	5
Petroleum Information	12
Schlumberger Well Surveying Corp.	14
Shaffer Tool Works	1
Stearns-Rogers Mfg. Co.	13

R. W. French, Jr.

R. L. Hoss

Last of the Chapters

STRONG SOUTHERN CALIFORNIA PETROLEUM SECTION FORMED

DAVID K. HAYWARD
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The Pacific Petroleum Chapter, long one of the strongest groups in the Petroleum Branch, has now gained new strength and prestige by becoming the Southern California Petroleum Section of AIME.

This is the last Petroleum Branch "chapter" to convert to local section status, putting an end to an awkward structure caused by the chapter designation. The recent AIME by-law change allowing local sections to over-lay made possible the conversion of all chapters to local section status.

With 597 members at present, the Southern California Petroleum Section becomes the second largest local section in the Petroleum Branch. It is one of the most active, sponsoring the major meeting formerly known as the Pacific Petroleum Chapter Fall Meeting and providing two meetings per month—the regular section meeting and meetings of the Junior Petroleum Group.

Junior Group Was Forerunner

This Junior Petroleum Group, which was discussed in the Report and Interpretation column in the November issue of PETROLEUM TECHNOLOGY, was the forerunner of the Pacific Petroleum Chapter which was formed in 1946. In 1938 the Junior Group was organized by young petroleum members who desired their own forum. Prior to its organization, all Petroleum members had been taking part in meetings of the Southern California Local Section, which was primarily active in the fields of mining and metallurgy.

The young men who were instrumental in forming this Junior Petroleum Group are today well known in the Petroleum Branch and the industry. Among the leaders were: John E. Sherborne, Union Oil Co., Petroleum Branch chairman in 1950; Paul Andrews, Signal Oil & Gas Co., Petroleum Branch vice-chairman in 1950; Richard W. French, Jr., Sohio Petroleum Co., Petroleum Branch chairman in 1951, and Edmund C. Babson, Union Oil Co., both members of the AIME Board of Directors; Charles R. Dodson, National City Bank of New York, 1954 Branch Executive Committee member; Carlton Beal, consulting engineer, Petroleum Division vice-chairman in 1948; and Everett G. Trostel, DeGolyer & MacNaughton, past local section chairman as well as former chairman of Petroleum Branch committees on engineering research and production.

William W. Porter, II, petroleum consultant, former member of the Branch Executive Committee; and Ernest K. Parks, petroleum consultant, former local section chairman, are others who aided in the setting up of the Junior Group. Porter later became first chairman of the Pacific Petroleum Chapter upon its formation in 1946.

Chapter Formed in 1946

Soon after its inception, other Petroleum Branch leaders joined the Junior Group, such as: John R. McMillan, Monterey Oil Co., 1954 Branch chairman; Howard Pyle, Monterey, member of AIME Board of Directors; Richard L. Parsons, California Research Corp.; Milan Arthur, Union Oil Co.; John Sinclair, Panuco Oil Leases, Inc.; and Marshall Turner, Phillips.

When in 1946 the Pacific Petroleum Chapter was formed to provide another forum for the growing membership in California, the Junior Group continued to function as a sub-section of the Chapter. It has been very important in the growth of the Chapter through the years, and now will be a continued asset to the Southern California Petroleum Section.

A current example of the dynamic influence of the Junior Group can be taken from its record during 1954. James P. Garten, of Long Beach Oil Development Corp., served as chairman, and his fortunate combination of personality and capacity for work guided the group through a year characterized by excellent coverage of technical subjects, procurement of top-notch speakers, drawing of capacity attendance, and the continued building of funds for long range projects such as the Cedric K. Ferguson Memorial Award, initiated by the 1953 group.

Petroleum Section Jurisdiction

The jurisdiction of the Pacific Petroleum Chapter originally covered all of California, but in early 1954 the San Joaquin Valley Local Section was founded by members in the San Joaquin Valley area. The jurisdiction of the Southern California Petroleum Section will not encompass either this area or the San Francisco area, but will cover the same territory as the Southern California Petroleum Section.

Counties served by the new section are: Los Angeles, Ventura, Riverside, Orange, San Bernardine, San Diego, and Imperial counties, and the western part of Santa Barbara County that is not included in the San Joaquin Valley Local Section territory.

1954 and 1955 Officers

Milton E. Loy, Schlumberger, was chairman of the Pacific Petroleum Chapter in 1954. Other officers were: Kemp Barley, Baroid, vice-chairman; J. A. Klotz, California Research, secretary; and Max Taves, Richfield, treasurer. Junior Petroleum Group officers in addition to Chairman Garten were: David K. Hayward, Texas Co., secretary; Charles E. Downey, Richfield, treasurer; and Thomas A. Johnson, Jr., Southern California Gas Co., program chairman.

H. M. Stanier has been elected for the honor of being the first chairman of the Southern California Petroleum Section. Other 1955 officers are: D. G. Kingman, General, vice-chairman; Henry Abadie, Long Beach Oil Development Co., field trip; J. P. Garten, membership; Hugh Barton, Humble, publicity; C. F. Gallagher, Schlumberger, petroleum forum; Sam Grinsfelder, Union, fall meeting.

Junior Petroleum Group officers for 1955 are: Oran L. Haseltine, Signal, chairman; Richard L. Perrine, California Research, vice-chairman; Richard Stegemeier, Union Oil, recording secretary; Roy Murdock, General, corresponding secretary; Norman E. Godbe, Signal, treasurer; Warren M. Marshall, III, Shell, Program; Don I. Shimmon, Southwest Exploration, arrangements; and Joe J. Mendoza, Texas Co., publicity.

★★★

Of Spring and Things, or . . .

HOW YOU CAN SAVE MONEY

VIRGINIA B. DAGGETT

ASSISTANT SECRETARY
PETROLEUM BRANCH, AIME

The connotations of Spring to the mind and the spirit of man would defy enumeration. You can *think* about other seasons of the year, but Spring evokes a vision—whether of a trout-filled stream, an azalea garden, or a Texas dust storm.

From our desk in the Petroleum Branch office, the vision of Spring traditionally means a chance to attack projects that have been put aside during the busy Fall and Winter in favor of more pressing activities. One such project recently completed was a mailing to our list of some 3,000 prospective AIME members concerning books.

The gist of the message is that the Petroleum Branch of AIME can save members a good bit of money. This approach may conceivably appeal to certain prospective members more strongly than other benefits, and will likely be of some interest to present members as well.

For example, we found that an AIME member can save nearly half the amount of the initiation fee through discounts on only three books. Junior Members, who pay no initiation fee, could easily regain the cost of a full year's dues through discounts on useful books they would probably buy anyway. If a member should order the entire list of current AIME-published and commercially published books, he would save $28.25, an amount equivalent to the initiation fee plus 41 per cent of annual dues. Though it is unlikely that any one member would order the complete list of books, the fact remains that the savings on publications are worth consideration.

Readers of this page are no doubt familiar with the annual volumes and special publications of the Petroleum Branch. These are furnished members at discounts of from 30 to 50 per cent.

In addition, members can buy through the Branch office in Dallas 11 books by commercial publishers at discounts ranging from $ .50 to $3.10. These include such classics as Muskat's *Physical Principles of Oil Production* and Calhoun's *Fundamentals of Reservoir Engineering*, as well as other books of general and specialized interest.

A list of these books were published in the JOURNAL OF PETROLEUM TECHNOLOGY last December, and was distributed with preprints at the Fall Meeting. Because of changes in publishers' prices, we have been forced to raise our prices on several of the books. A new price list and order form is available on request from the Petroleum Branch office in Dallas. In order to reduce handling costs and extend members the maximum possible discount, we must request payment in advance on these book orders.

We believe the distribution of technical literature is one of our most important areas of service to members, and one where membership is of decided dollar-and-cents value. We invite all members to take advantage of the publications now available, and we look forward to the time when we can expand this service to give members increased dividends in publications. ★★★

Proposed for Membership, Petroleum Branch, AIME

TOTAL AIME membership on Dec. 31, 1954, was 21,816; in addition 2,179 Student Associates were enrolled.

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The Institute desires to extend its privileges to every person to whom it can be of service, but does not desire as members persons who are unqualified. Institute members are urged to review this list as soon as possible and immediately to inform the Secretary's office if names of people are found who are known to be unqualified for AIME membership.

In the following list C/ means change of status; R, reinstatement; M, Members; J, Junior Member; A, Associate Member; S, Student Associate.

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San Francisco—Hines, LeRoy H. (A).

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Denver—Gear, George Lewis (A).
Englewood—Gibson, James William (R, M).
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Indiana
Evansville—Stegelman, Arthur, Jr. (M).

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Pratt—Price, William Henry (J).
Wichita—Franey, William Richard (M); Ross, John B. (C/S-A-M).

Louisiana
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Mississippi
Natchez—Hines, Leo E. (M).

Montana
Billings—Andrew, Charles Fleming (A); Bishop, William Don (A); Scott, William Allen (C/S-A-M); Whitaker, Paul Wesley (M).

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Princeton—Maxwell, John Crawford (M).
Teaneck—Harris, Charles DeWitt (M).

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Hobbs—Layhe, Robert Eugene (R, C/S-S-M).

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New York—Jaekel, Julie Anne (R, J).

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Williston—Bax, Robert Walter (M).

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Sinton—Simms, James Jefferson (M).
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Wichita Falls—Moore, Roy Geraldine (M).

Wyoming
Casper—DeStefano, Sam Frank (J); Spieles, Earl Loyd (C/S-A-M).

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Calgary, Alta.—Connor, Eric James (C/S-A-M); Matthews, Milton W. T. (J); Whitaker, George van Someren (J).

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Bogota—Gartner, Jean Eugene (M).

Costa Rica
San Jose—Arnaud, Jean A. M. (J).

France
Begles—Curutchet, Jean Emile (M).

Persian Gulf
Awali, Bahrain — Benn, Peter James (J); Clark, Peter (J).

Peru
Lobitos—Cabrera, Augusto C. (M).

Portuguese West Africa
Luanda—Devresse, Ephrem Ghislain (J).

Venezuela
Barcelona—Dinda, Janos Ferenc (M); Skiba, Francis Felix (J).
Caracas—Hall, William Robert (M); Williams, James Edward (J).
Maracaibo — Landrum, Ray Edward (M); Siero, Luis Enrique (J).

EMPLOYMENT NOTICES

The JOURNAL will post notices of men and jobs available. Companies and AIME members are invited to use this space, for which there is no charge. Except as noted below, address replies to: Code (appropriate number), JOURNAL OF PETROLEUM TECHNOLOGY, 800 Fidelity Union Bldg., Dallas 1. These replies will be forwarded unopened and no fees are involved.

PERSONNEL AVAILABLE

☆ Petroleum Engineer with 4½ years' experience desires position in the Rocky Mountain area, preferably Denver. Graduate from Colorado School of Mines in 1949, married, two children. Now employed and in charge of drilling, production, workovers, and waterflood project for independent. Code 244.

☆ June Petroleum Engineering Graduate from University of Houston desires position with small company or consulting firm in the southwest. Married, 27, presently employed in reservoir section of small oil company. One year of experience in bottom-hole pressure and split stream sampling, and 1½ years' experience in gas measurement. Code 245.

☆ Petroleum Engineer and Geologist with MS degree, some research experience and approximately nine years' field work in geology and petroleum engineering, mineral exploration, and water well drilling. Presently employed as drilling superintendent in a governmental department. Would like to return to his original line of work either in geology, drilling, or production of oil in Canada or South America. Married, 38, one child. Code 246.

☆ Geological Engineer with five years' exploration and evaluation experience with major oil companies in the Mid-Continent area desires position in New York or vicinity. Has Kansas PE license. Code 247.

POSITIONS OPEN

☆ Petroleum Engineer, with MS or PhD in chemistry, mechanical or petroleum engineering, for research and teaching in reservoir mechanics and related fields at rapidly growing southwestern institution. Rank and salary open, 12 months employment possible, consulting work encouraged and available in immediate areas. Applications will be kept confidential. Code 572.

☆ Major Oil Company has openings in New York City and in its foreign operations for graduate petroleum engineers with experience, and for recent graduates in this field to perform engineering work in development, production, drilling, process and oil and gas engineering on primary and secondary recovery. Write giving full particulars regarding personal history and work experience. Code 573.

☆ Major university seeks applicants for teaching positions up to and including full professorship. Salary up to $8,500 for the school year depending upon qualifications. Reply giving full details, age, professional experience, academic record, publications, references. Code 576.

☆ Research Engineer. Major oil research company has opening for PhD or MS with minimum of three years' research experience in the field of reservoir mechanics. Opportunity for original work. Send detailed education and experience record, age, and state salary expected. Code 579.

PETROLEUM GEOLOGIST

Man with 8 to 10 years' experience in oil field mapping wanted to work for staff of large producer, with headquarters in Rocky Mountains. Duties will include detailed surface mapping.

Give references, details of education and experience, and salary expected in letter, and include photograph. Code 581.

PETROLEUM ENGINEER

Have an opening for a petroleum engineer for patent liaison work, preferably with field experience. The work involves evaluation of ideas and data, accurately describing and delineating inventions, advising patent attorneys on technical questions, and collaborating with attorneys and inventors in the preparation of patent applications. The position, at a large integrated petroleum research laboratory, affords contact with various aspects of drilling and production. Code 582.

☆ Graduate Assistantship available July or Sept. 1 in petroleum production engineering research on fluid flow in porous media. Exemption from most fees and $131 per month. Code 583.

☆ Independent has opening for a petroleum engineer with two or more years of experience in production. Location and work to be in Arkansas-Louisiana-Texas area. Write giving full particulars regarding personal history and experience. Applications will be kept confidential. Code 584.

☆ Natural Gas Engineer for research on gas storage and producivity of natural gas wells. Research involves the basic theory of fluid flow. Background experience required in well testing and gas measurement. Reply giving full details as to education, professional experience, references, and salary expected. Code 585.

☆ Major Oil Company with operations in West Texas and New Mexico has openings for engineers with minimum of two years' experience in reservoir work. Write giving full information regarding personal history and work experience. Code 586.

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BRATT NAMED ADVERTISING MANAGER of JOURNAL of PETROLEUM TECHNOLOGY

Maurice D. Bratt has been appointed advertising manager of the JOURNAL OF PETROLEUM TECHNOLOGY. He will also serve as an assistant secretary of the Petroleum Branch in the Dallas office.

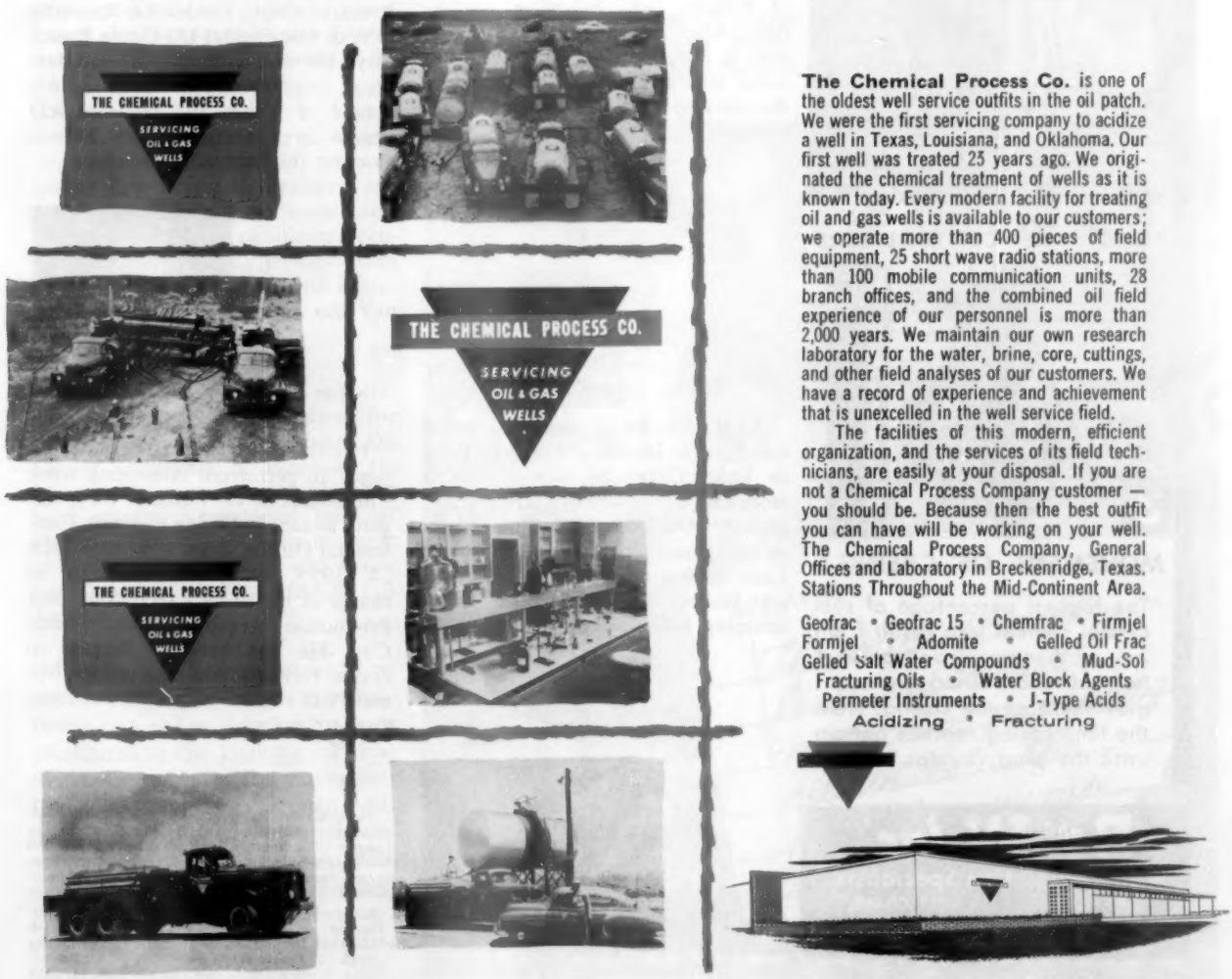
Bratt will represent the magazine nationally in advertising sales. As assistant secretary, he will be active in both the sales promotion and market research activities of the Petroleum Branch. He replaces R. C. Wipperman, who resigned in January.

A 1949 graduate in advertising and marketing from Southern Methodist University, he has since been engaged in advertising and sales promotion activities for Dallas retail, motor transportation, publication, and life insurance organizations. He is a veteran of five years in the Marines, having served as an enlisted man in World War II and as an officer during the Korean conflict.

Bratt is active in the Dallas Advertising League as chairman of its Publications Committee, a member of the board of directors of the North Texas Chapter of the National Industrial Advertisers Association, and a member of the First Community Church of Dallas.

Maurice D. Bratt

Originally from Syracuse, N. Y., he now resides in Dallas with his wife and two small daughters.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MEET the AUTHORS

Biographical sketches of PAUL B. CRAWFORD and BOBBY L. LANDRUM were published in the February 1955 issue of JOURNAL OF PETROLEUM TECHNOLOGY.

R. E. HURST is district engineer for Dowell at Midland. He received his BS degree in electrical engineering from Oklahoma A&M and joined Dowell as a junior service engineer at Borger, Tex., following graduation. After becoming district engineer at Borger, he was transferred to Tulsa where he was associated with the development of new fracturing methods.

J. M. MOORE is assistant district manager for Dowell at Midland. Born in Enid, Okla., he was graduated from the University of Oklahoma in geology. He joined Dowell in 1939 as equipment operator in Flora, Ill. Later he was transferred to Midland and became district engineer before attaining his present position.

D. E. RAMSEY is manager of operations for Dowell at Tulsa. Having graduated from Texas A&M in petroleum engineering, he joined Dowell as service engineer at Hobbs in 1948. He was transferred to Midland as sales engineer, became district engineer in 1952, then district manager. He was promoted to his present position in 1954.

FRED J. RADD is senior research metallurgist in the Development and Research Dept., Production Research Div. of Continental Oil Co. in Ponca City. He is a graduate in metallurgical engineering from Missouri School of Mines and holds a ScD degree in metallurgy from Massachusetts Institute of Technology.

LEENDERT DE WITTE is now engaged in petroleum consulting work with offices at 1791 Ocean Way, Laguna Beach, Calif. He was with Continental Oil Co. from 1951 to March 24, 1955, being most recently in charge of the physics section of their Production Research Div., Ponca City. He was born in Bergen op Zoom, Holland, and received his MS and PhD degrees in geophysics from California Tech.

Necrology

John Greer Bartram, 61, consulting geologist for Stanolind Oil & Gas Co., died in Casper of a heart attack on Feb. 18. He had been with Stanolind since 1931, having transferred from Midwest Exploration Co. when it became part of Stanolind.

Date Elected	Name	Date of Death
1946	Donald W. Bell	April, 1954
1942	James W. Miles	Unknown
1914	William D. Waltman	Feb. 14, 1955

PERSONALS

ROBERT L. HOSS, formerly affiliated with Midwest Oil Corp., has joined Vaughey & Vaughey as production superintendent in the Rocky Mountain area, with headquarters in Denver. After graduation from the University of Tulsa in 1942 and prior to entering the armed forces, he worked with Phillips Petroleum Co. He received an MS degree in petroleum engineering from The University of Texas in 1947 and served with Humble Oil and Refining Co. for several years. In 1948 Hoss was awarded the AIME Alfred Nobel prize for his paper on "Calculated Effect of Pressure Maintenance on Oil Recovery." He is chairman of the Denver Petroleum Section.

C. R. DODSON is now assistant vice-president and petroleum engineer in the Petroleum Dept. of The National City Bank of New York. He joined the bank shortly over one year ago. Dodson is a former member of the Petroleum Branch Executive Committee and is a nominee for AIME Board of Directors.

C. C. O'BOYLE, Denver geological engineer, has affiliated with the consulting firm of A. E. Brainerd and F. M. Van Tuyl. These consultants are specializing in petroleum, economic and engineering geology. Each retains his separate office, with Brainerd and O'Boyle in Denver and Van Tuyl in Golden, Colo.

BASIL KANTZER has been appointed acting manager of operations for the Gulf Coast Div. of Union Oil Co. of California in Houston. He relieves DUDLEY TOWER who has been granted a temporary leave of absence. Kantzer has been manager of Union's Natural Gas and Gasoline Dept. with headquarters in Los Angeles.

EDWARD J. HAMNER, manager of Humble Oil & Refining Co.'s California area at Los Angeles, has been transferred to the Houston office as assistant manager of the Exploration Dept. This is a newly created position. JOHN S. BELL, formerly assistant manager of the area, was promoted to manager replacing Hamner. He now has supervision of both exploration and production activities for Humble in the California area.

W. B. EMERY (left), who has been with Ohio Oil Co. for 36 years, retired on April 1. He was a director and vice-president of production at the time of his retirement. Holding a PhD from Yale, Emery joined Ohio Oil Co. in 1919 after working for five years with the United States Geological Survey. In the changing of positions following Emery's retirement, GLEN B. GARIEPY (right) was made chief geologist. He joined Ohio in 1926 as a field geologist after graduating from the University of Wyoming and completing graduate work at Wisconsin and Stanford universities. He was assistant manager of the company's Shreveport Div. when he accepted the new appointment.

GAIL F. MOULTON, of Rockefeller Bros., Inc., New York City, has been re-elected treasurer and controller of the AIME for the usual one-year term. William J. Masson, an assistant to Moulton in the office of Rockefeller Bros., was re-elected assistant controller.

ERNEST H. KOEPF has joined the administrative staff of Core Laboratories, Inc., Dallas, as manager of the company's Research and Development Dept. He began his professional career in 1939 with The Atlantic Refining Co. after receiving his PhD degree in chemical engineering from The University of Texas, and worked for that company until 1952. Then he became vice-president and general manager of Texas City Chemicals, Inc. In 1954 he returned to Atlantic, then recently accepted his present position with Core.

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Officers Named for USC Chapter

Officers for the University of Southern California Student Chapter are: Donald N. Forster, president; Donald P. Walker, vice-president; Dov Amir, secretary; Leland B. Cecil, treasurer; and Oran Haseltine, Signal Oil and Gas Co., Los Angeles, counselor.

Petroleum Register Released

The 1955 edition of *International Petroleum Register* has been released. Henry J. Struth, Member AIME, is editor of this 606 page publication which is published yearly. Petroleum companies throughout the world are listed alphabetically in a single section regardless of country or division of the industry in which they operate. Separate lists are also included of producing and pipelining companies. The book may be obtained from Palmer Publications, 604 Fifth Ave., New York 20, N. Y.

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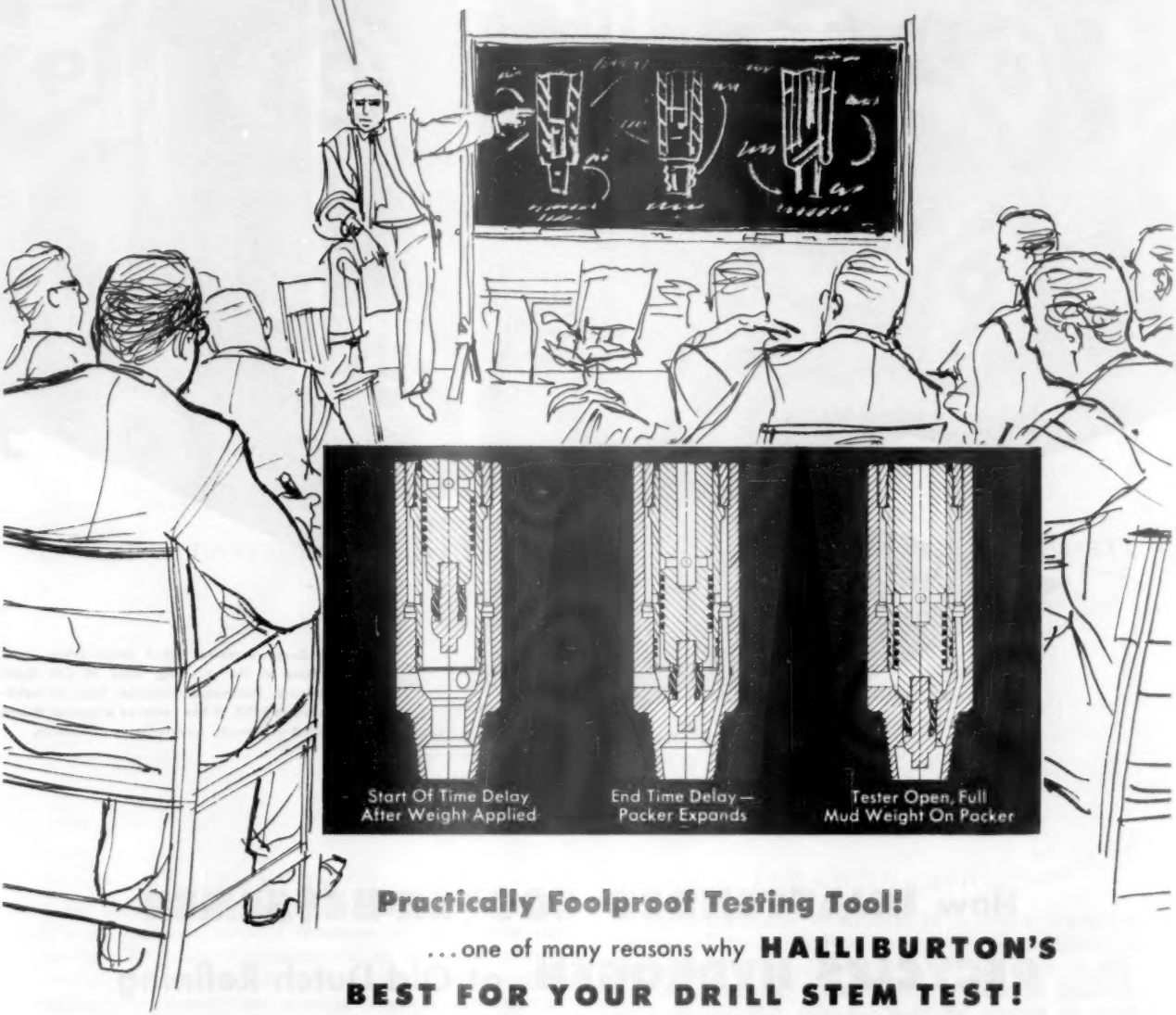

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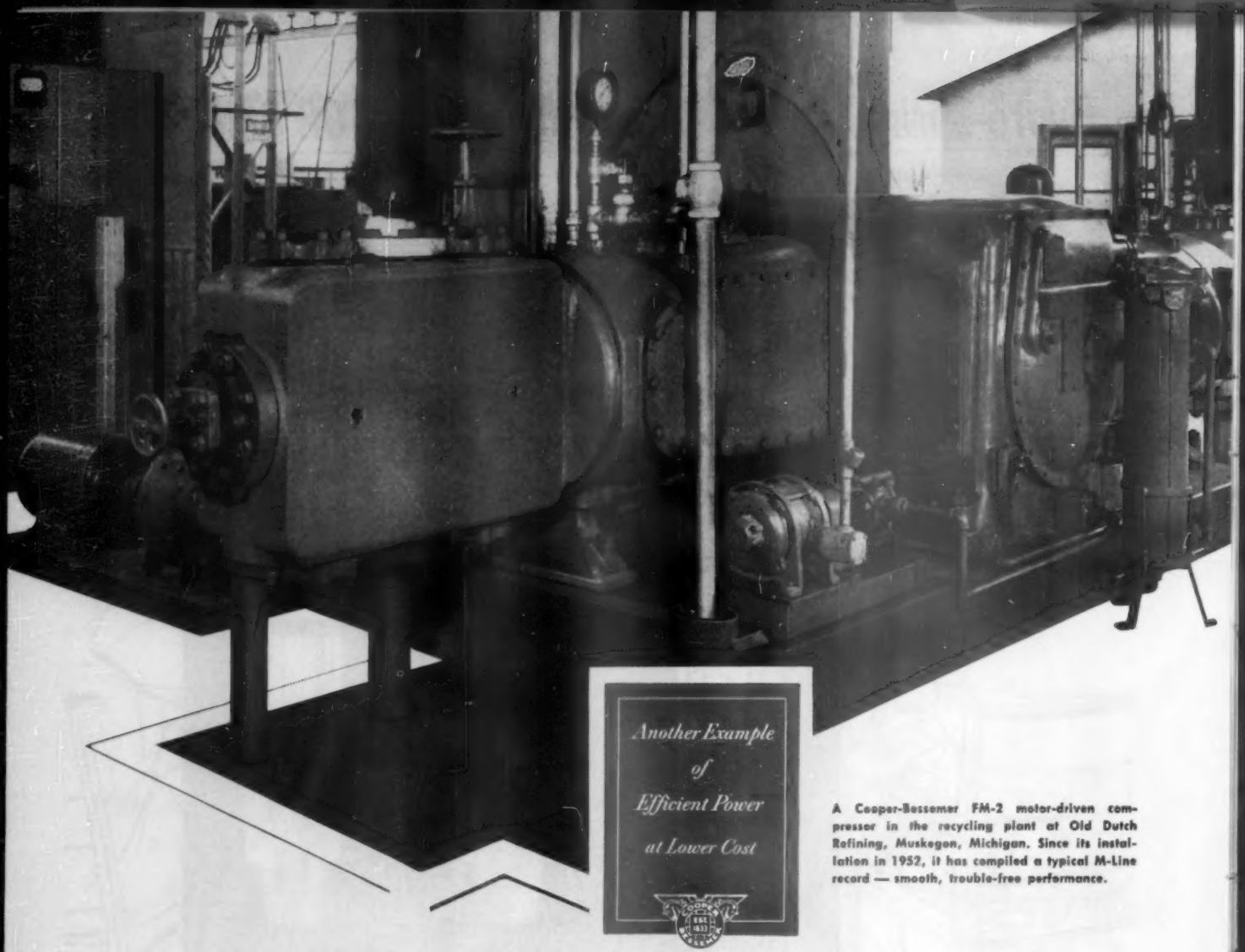

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TECHNICAL NOTE 275

EFFECT of UNSYMMETRICAL VERTICAL FRACTURES on PRODUCTION CAPACITY

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MEMBER AIME
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ABSTRACT

Electrical model studies have been made of the effect of unsymmetrical vertical fractures on production capacity. The study was restricted to the case of two vertical fractures originating at the well and extending out into the reservoir for various distances and orientations. The ratio of the short fracture length to the long fracture length was varied from 0.1 to 1.0 in successive studies. The angle separating the two fractures was varied from 0 to 180 degrees.

The most effective fractured patterns were obtained when the fractures were oriented 180 degrees. It was found that when the total fracture length was equal to 0.2 of the drainage radius, the increase in production capacity may vary from approximately 1.55 to 1.95, depending upon the ratio of the short fracture length to the long fracture length and the angle separating the two fractures. If the total fracture length were 0.5 of the drainage radius, production capacity increases varying 1.95 to 2.65 were observed, depending on the angle between the fractures and the ratio of the short fracture length to the long fracture length.

The fractured well production capacity decreased approximately 1 to 10 per cent as the angle separating the fractures was varied from 180 to 90 degrees. It was dependent on the particular fracture.

[1]References given at end of paper.
Manuscript received in Petroleum Branch office on May 19, 1954.

INTRODUCTION

The commercial application of reservoir fracturing techniques has caused an interest to be expressed in the effect of vertical and horizontal fractures on production capacities. Some data have indicated that substantially vertical fractures may be created in some reservoirs. It is believed that the fractures are possibly unsymmetrical, that is, one fracture may extend due north 100 ft and a second fracture on the opposite side of the well may extend south or southeast only 50 ft. The total fracture length, ratios of the lengths and angles of separation may vary considerably. For this reason variations in these factors were considered. The study was restricted to the case of two vertical fractures originating at the well and extending out into the reservoir. It is not known that such will occur in a reservoir, but the results may be of value in interpreting or studying fracturing applications.

PROCEDURE

An electrical model was used in this study of the effect of unsymmetrical vertical fractures on production capacity. A wooden tank 30 in. in diameter and approximately 2 in deep was coated with paraffin wax. A copper band was situated at the periphery and a single wire electrode was positioned at the center of the tank. The ratio of the reservoir radius divided by the

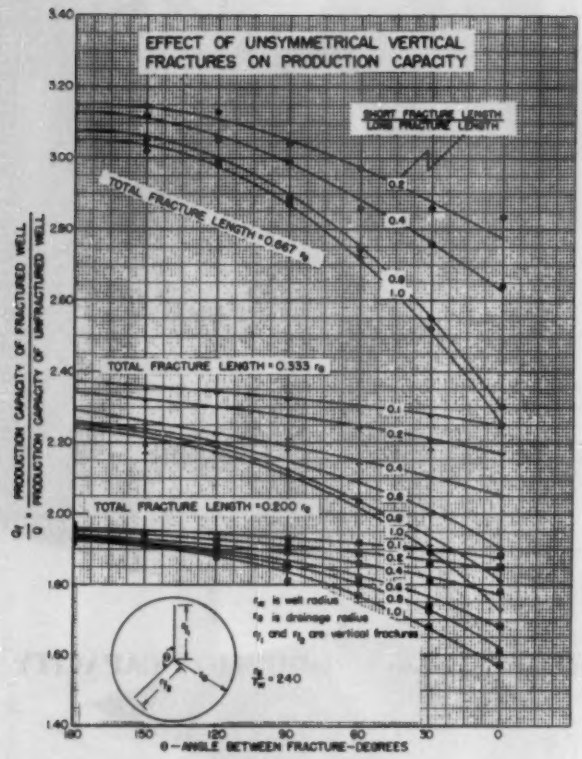
EFFECT OF UNSYMMETRICAL VERTICAL FRACTURES ON PRODUCTION CAPACITY
SHORT FRACTURE LENGTH / LONG FRACTURE LENGTH
TOTAL FRACTURE LENGTH = 0.667 r_e
TOTAL FRACTURE LENGTH = 0.333 r_e
TOTAL FRACTURE LENGTH = 0.200 r_e
PRODUCTION CAPACITY OF FRACTURED WELL / PRODUCTION CAPACITY OF UNFRACTURED WELL = q_f / q
θ—ANGLE BETWEEN FRACTURE—DEGREES
r_w is well radius
r_e is drainage radius
r_1 and r_2 are vertical fractures
$\frac{r_e}{r_w}$ = 240

FIG. 1

well radius was equal to 240. The tank was filled to a depth of approximately 1 in with a dilute salt solution. (See inset of Fig. 1 for a top view of the apparatus.)

An electrical potential was applied to the copper band situated at the periphery of the vessel and the single wire well in the center. The flow of current or resistance was measured for this particular system. Two vertical copper sheets were fastened to the wire well to simulate two vertical fractures which might originate at the well and extend out into the reservoir for various distances. In separate experiments the ratios of the length of the short fracture to the long fracture were varied from approximately 0.1 to 1.0.

The angle separating the two fractures was varied from 0 to 180 degrees in 30 degree intervals. At each position the flow of current or system resistance was measured and compared with that using only the wire well. The data obtained from such a study indicate the increases in steady-state production capacity which may be expected in fracturing uniform homogeneous reservoirs where the resistance to flow in the fracture is negligible compared with that in the matrix. For reference on electrical models for perforation studies see McDowell and Muskat[2] and Howard and Watson[1].

DISCUSSION AND CONCLUSIONS

Fig. 1 shows the effect of unsymmetrical vertical fractures on production capacity. The abscissa shows the angle separating the fractures; the ordinate shows the production capacity of the fractured well divided by the production capacity of the unfractured well. The upper family of curves in the figure shows the results obtained when the total fracture lengths, that is, the sum of the short fracture plus the long fracture, were equal to 0.667 of the drainage radius. The center and lower groups of curves were obtained when the total fracture lengths were 0.333 and 0.200 of the drainage radius, respectively.

It will be noted that when the total fracture length was 0.667 of the drainage radius, the short fracture length divided by the long fracture length 0.2, and the angle separating the fractures 180 degrees, an increase in production capacity by a factor near 3.15 was observed. If the short fracture was rotated so that the angle of separation was 150 degrees, the production capacity was near 3.14. When the short fracture was 90 degrees to the long fracture, a production capacity of 3.05 was observed. As the angle of separation became zero the production capacity was indicated to be near 2.8. Note that when the angle is zero degrees, the increase in production capacity is that which would be observed for a single vertical fracture whose length is that of the long fracture. For this particular fracture combination there appears to be very little difference in production capacity regardless of whether the angle of separation is 180 or 150 degrees. However, if the angle of separation is between 0 and 90 degrees there may be considerable decrease in the effectiveness of the fracture to increase the production capacity. When the angle separating the fractures was near 180 degrees and the two fractures were of the same length it will be noted that a production capacity increase of 3.05 was observed. For 90 and 0 degrees separation production capacities of 2.87 and 2.25 were observed, respectively.

The center family of curves shows the increase in production capacity when the total fracture length was equal to 0.333 of the drainage radius. It will be noted that for the case in which the short fracture length divided by the long fracture length was 0.1, and the angle separating the fractures was 180 degrees, a production capacity of 2.37 was observed. The production capacity decreased to approximately 2.32 when the angle separating the fractures was 90 degrees. At zero degrees separation a production capacity of 2.25 was observed. It will be noted that a production capacity between 1.73 and 2.37 would be expected if the total fracture length were near 0.333 of the drainage radius. The exact production capacity would depend on the ratio of the short fracture length to the long fracture length and the angle separating the fractures.

The lower family of curves in Fig. 1 shows the changes in production capacity that were observed when the total fracture length was 0.200 of the drainage radius. For the case in which the short fracture length divided by the long fracture length was 0.1, and the angle separating the fractures was 180 degrees, a production capacity increase of near 1.95 was observed. When the angle separating the fractures was 90 degrees a production capacity of 1.93 was observed. A production capacity of 1.87 was observed when the angle separating the fractures was zero degrees. For the case

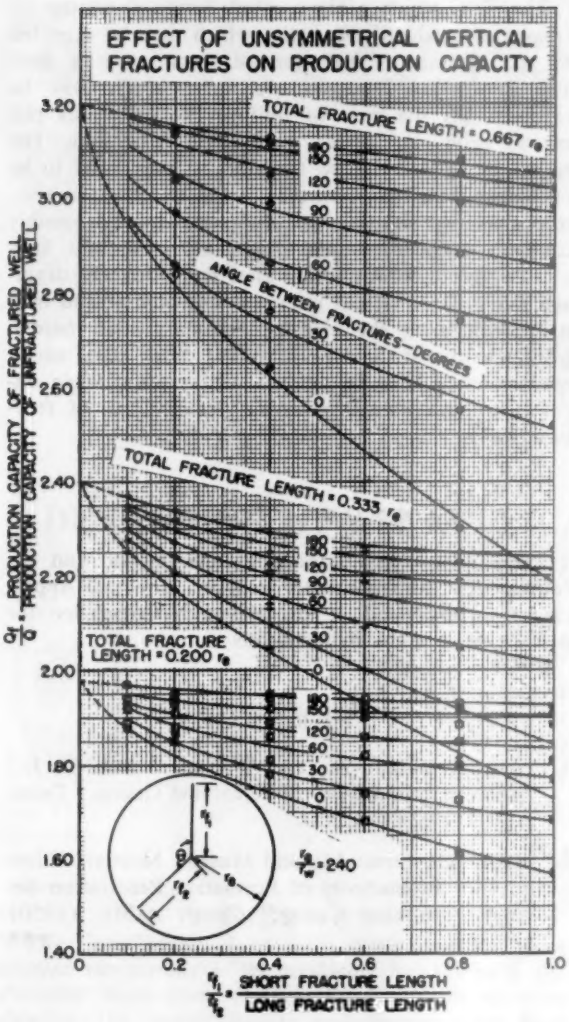

FIG. 2 — CROSS PLOT OF DATA IN FIG. 1.

in which the "short" fracture length divided by the "long" fracture length was equal to 1.0, and the angle separating the fractures was 180 degrees, a production capacity of near 1.93 was observed. The production capacity decreased as the angle separating the fractures decreased. A minimum was observed for zero degrees separation.

Fig. 2 is a cross plot of the data shown in Fig. 1. The abscissa shows the ratio of the short fracture length divided by the long fracture length and the ordinate shows the production capacity of the fractured well divided by the production capacity of the unfractured well. The upper family of curves in Fig. 2 shows the changes in production capacity that were observed when the total fracture length was maintained at 0.667 of the drainage radius. These data show that the production capacity decreases from approximately 3.2 to 3.05 as the ratio of the short fracture length to the long fracture length varies from near zero to 1.0, and the angle between fractures is 180 degrees. It will be noted that a decrease in production capacity is expected if the angle of separation becomes less than 180 degrees. The center and lower family of curves show the changes in production capacity for the case in which the total fracture lengths are near 0.333 and 0.200 of the drainage radius, respectively.

Fig. 3 shows the effect of unsymmetrical vertical fractures on production capacity for the case in which the short fracture length divided by the long fracture length is equal to 0.4. The abscissa shows the total fracture length divided by the drainage radius. The total fracture length is the sum of the short and long fractures. The ordinate shows the increase in production capacity of the fractured well. Note that if the total fracture length is near 0.200 of the drainage radius that a production capacity increase between 1.74 and 1.95 may be expected, the former occurring for the case of zero degrees angle of separation, and the latter occurring for the case of 180 degrees separation. If the total fracture length is near 0.5 of the drainage radius production capacities between 2.3 and 2.65 may be expected, depending upon the angle of separation. It should also be noted that over the range in which data are presented there is a very rapid increase in production capacity for fracture lengths up to 0.2 of the drainage radius, after which the slopes of the curve change and the increase in production capacity is less sensitive to fracture length within certain limits.

Fig. 4 shows the effect of unsymmetrical vertical fractures on production capacity when the two fractures are of the same length. For the case in which the total fracture length is 0.2 of the drainage radius it is noted that production capacities varying from

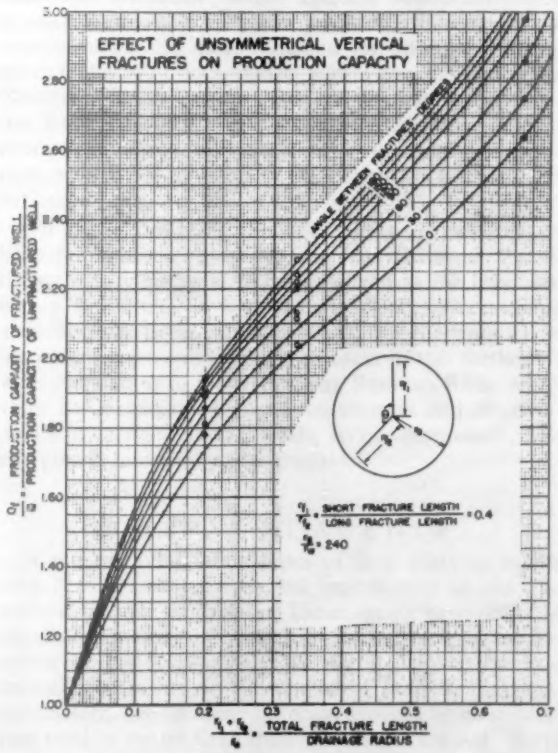

FIG. 3 — EFFECT WHEN SHORT FRACTURE LENGTH DIVIDED BY LONG FRACTURE LENGTH EQUALS 0.4.

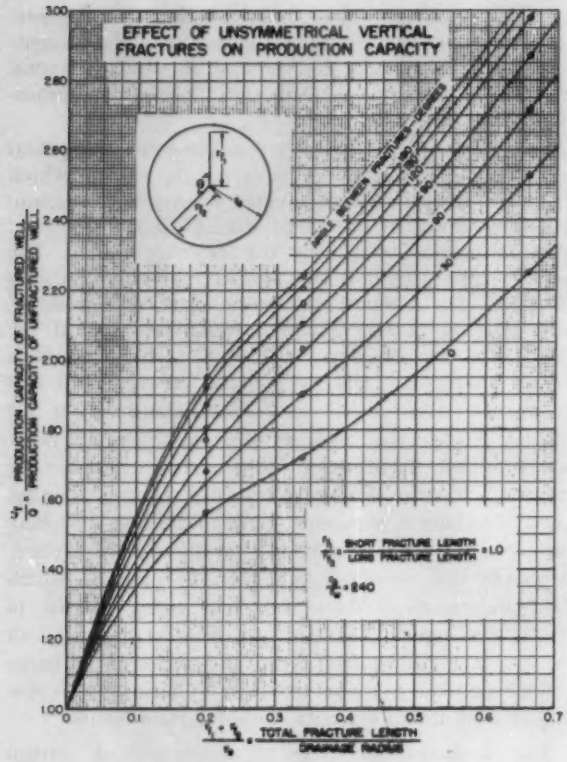

FIG. 4 — EFFECT WHEN THE TWO FRACTURES ARE OF THE SAME LENGTH.

near 1.55 to 1.95 may be expected, depending upon the angle of separation. If the total fracture length is near 0.5 of the drainage radius production capacities varying from 1.95 to 2.65 would be expected.

The data which are presented herein show the increases in production capacity which may be expected by the creation of two vertical fractures at a well. The production increases are those which may be expected for the case of uniform homogeneous reservoirs producing under steady-state conditions. The resistance to flow in the fractures is considered to be negligible compared with that in the matrix. It is realized that few, if any, actual reservoirs will possibly conform to the flow under such ideal conditions. It is also desired to point out that after fracturing, the drainage radius in an actual reservoir may change and may not conform to the circular boundary used herein. Consequently, it is suggested that these data which are presented here be applied with caution when endeavoring to estimate reservoir performance of fractured wells.

ACKNOWLEDGMENT

The authors wish to acknowledge the aid and encouragement of George H. Fancher, director. Appreciation is expressed to the Research Committee for permission to publish the results.

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2. McDowell, James M., and Muskat, Morris: "Effect on Well Productivity of Formation Penetration Beyond Perforated Casing," *Trans.* AIME (1950) **189,** 309. ★★★

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PETROLEUM TRANSACTIONS

DEVELOPMENT and APPLICATION of "FRAC" TREATMENTS in the PERMIAN BASIN

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ABSTRACT

The "frac" method of well stimulation has been applied successfully to all producing formations in the Permian Basin area. During the five years since its development, many changes and improvements have been made in treating materials, procedures, and equipment.

A number of fluid carrying agents, having different physical and chemical properties, have been developed to meet various well requirements. The current trend is toward larger gallonage treatments, employing higher injection rates. The use of "down-the-casing" techniques has greatly reduced high surface working pressures, attributable to friction losses resulting from injection through tubing.

Petrographic studies of various Permian Basin formations, coordinated with laboratory and well log data, have been found a valuable guide in planning frac treatments. A knowledge of the extent and orientation of naturally occurring fractures and planes of weakness in the formation, aid in predicting the ultimate drainage pattern resulting from the frac treatment.

INTRODUCTION

The South Permian Basin covers an area in West Texas and New Mexico about one-half the size of the state of Texas. This vast region has been called the "Permian Basin" for so long that the term will be used here. It includes an area south of the Matador Arch, approximately 250 miles wide and 300 miles long. Structural features of importance within the basin are the Northwest Shelf, Eastern Platform, Midland Basin, Central Basin Platform, and Delaware Basin. The principal producing formations include sand, limestone and dolomite, with lesser amounts of shale, anhydrite, chert, and various silicates.

All of the producing formations in the Permian Basin have responded to some type of frac treatment. Essentially, a frac treatment may be defined as the injection, into a formation, of a fluid carrying agent containing a particulated solid (usually sand), for the purpose of increasing production. The application of this method of well stimulation to many differing Permian Basin reservoirs has necessitated numerous changes and improvements in carrying agents, solids, service equipment, well equipment, and treating techniques.

CARRYING AGENTS

A number of different types of fluid carrying agents have been developed since the introduction of the frac method of well stimulation. These agents have different physical and chemical properties, and in many cases the extent of production increase derived from the frac treatment depends on the choice of fluid carrier. Unfortunately, due to many different systems of nomenclature used in the oil field, these differences are not always recognized by the oil operator. In general, carrying agents may be divided into the following broad classi-

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fications: (1) hydrocarbon gels, (2) aqueous gels (acid or water), (3) emulsions, (4) refined oil, (5) lease oil, and (6) miscellaneous fluids.

Hydrocarbon Gels

Most hydrocarbon gels used as carrying agents are quite similar, whether made from gasoline, kerosene, diesel oil, or crude oil. They are produced by adding a gelling or thickening agent (usually a metallic soap or the salt of a fatty acid) to the hydrocarbon. This results in materially increasing the viscosity of the fluid, the extent depending upon the concentration of gelling agent added. The ability of hydrocarbon gel to suspend sand is a function of the viscosity and density of the gel, and the size and shape of the sand grains.

These hydrocarbon gels may be caused to "break" or lose their viscosity in several different ways, depending upon the type of gelling agent used. The presence of an electrolyte, such as salt water or a mineral acid, will cause most of these gels to break. Thinning of the gel may also be accomplished by dilution with additional quantities of hydrocarbon fluid.

Aqueous Gels

Water-base gels, such as thickened hydrochloric acid, are similar in many respects to hydrocarbon gels. The type of gelling agent used (usually a carbohydrate or cellulose derivative) determines how the gel breaks and what will break it. As a rule, a gelling agent is chosen which will permit the gel to break on contact with the reaction products of the acid and the formation, or as a result of bacterial growth within the gel itself. Care should be taken not to use a gelling agent that will precipitate out in insoluble form after the acid has become spent. The sand suspending ability and fluid loss characteristics of these aqueous gels are related to their viscosity and density, as in the case of the hydrocarbon gels.

Gelled acids are adaptable to a wider variety of well conditions than are hydrocarbon gels, since the type of acid and concentration may be varied, dependent on the solubility of the formation. Additional agents, which minimize emulsifying and silicate-swelling tendencies of the acid, have been used to advantage in many areas. The viscosity of the gel may be varied over a wide range as desired.

The use of gelling agents for the thickening of fresh water or brine is desirable for frac treatments on fresh water wells or water injection wells, where the injection of oily fluids might be undesirable. Such gels are thinned by bacterial action or by dilution with formation fluid.

Emulsions

The term "emulsion" until recently has been synonymous with trouble in the oil fields. When properly used, however, emulsions have been found extremely helpful. Emulsions have a number of advantages and disadvantages when compared with the gels as possible carrying agents. Although they have high fluid loss in comparison with the true gels, they possess excellent sand carrying characteristics.

Essentially, an emulsion consists of a homogeneous mixture of two immiscible fluids, one of which exists in the form of tiny droplets as the inner phase, surrounded by the other fluid known as the outer phase. Normally such mixtures rapidly separate into two distinct layers; however, certain types of chemical compounds, known as emulsifying agents, have the ability to keep such liquids in emulsion form for indefinite periods of time. Such emulsifying agents frequently occur naturally in crude oils, resulting in troublesome emulsions of crude oil and brine. Such emulsions are thick and gooey, and interfere with the production of oil from a well.

The emulsions used as carrying agents in frac treatments are physically similar to these naturally occurring emulsions; however, the emulsifying agents used produce relatively unstable emulsions which tend to break down, once they have entered the formation. The two principal emulsion type carrying agents used in frac treatments are acid/kerosene emulsions, and crude oil/water emulsions.

The physical and chemical properties of an emulsion are determined by the emulsifying agent, the volumetric ratio of the two liquids in the emulsion, and the amount of agitation given the mixture.

Acid/kerosene emulsion type carrying fluids will break down on contact with acid reaction products, or because the emulsifying agent is adsorbed onto the formation. Oil/water type emulsions may be broken by the presence of any material tending to reverse the emulsion, so that water becomes the outer phase. Most emulsions are sensitive to heat. Regular crude oil treating compounds will usually break emulsion type carrying agents. Dilution of the outer phase will thin the emulsion to a lower viscosity.

One of the chief advantages of this type carrying fluid is that an external gel-breaker is not required to cause the viscous fluid to revert to a thin, free-flowing liquid. This is particularly advantageous in low bottom-hole pressure wells, where lengthy cleanup periods are required after other type frac treatments.

In most crude oil/water type emulsions, the water and emulsifying agent make up less than 4 per cent of the total volume. Such emulsions break down in the presence of an electrolyte such as brine or acid. They are readily thinned by dilution with crude oil. If a low fluid loss carrying agent is desired, the aqueous phase of the emulsion may be made from thickened fluids. Inert solid particles also may be added to reduce the fluid loss.

Refined Oils

The term "refined oils" as used here refers to any crude oil from which the very light and very heavy hydrocarbons have been removed. This would include kerosene, heavy fuel oils, and all intermediate products. Since the heavier oil fractions are more commonly used in frac treatments, they will be discussed first.

Certain green, paraffin-base crude oils when refined properly, will yield a dark green viscous product which boils between 350°F and 750°F at atmospheric pressure. This oil fraction, commonly called "fuel oil" by refinery personnel, can be made into an ideal frac fluid by blending with a high analine point hydrocarbon, such as kerosene or diesel oil, to thin to desired viscosity.

Kerosene and diesel oil have been used as carrying agents in wells already having open fractures. Such treatments are valuable in removing paraffin deposits from the formation and wellbore or to clean up emulsions caused by a previous treatment, drilling fluid, or formation water. When used in wells where emulsion difficulties have been encountered, a demulsify-

ing agent usually is added to the kerosene or fuel oil. It is important that preliminary tests be run to determine the proper agent to be used. Most refined oils have less tendency to form emulsions than does lease oil, due to the removal of fine solid particles by the refining process.

Care should be taken when using refined oil as a carrying agent to choose one having a pour point at least 20 degrees below the formation temperature of the well in order to avoid precipitation of wax crystals from the oil, a phenomenon taking place at 12 to 15 degrees above the pour point of the oil.

Lease Oils

At the start of most frac treatments, a volume of crude oil is pumped into the formation in order to determine the "breakdown" and feeding pressures, and the injection rate. In some cases it is possible to follow this with sand-laden crude oil, utilizing the crude oil as a carrying agent.

Such a procedure has certain advantages. For one thing, if the crude oil is from the well in which it is used, no emulsion trouble should be experienced. If a high gravity crude is used, the well should clean up readily.

Such advantages are, however, more than offset by the disadvantages attendant the use of crude oil as a carrying agent:

1. Most crude oils have very poor sand-suspending properties. Low concentrations of sand must be used or the crude will be difficult to pump and "screen-outs" are likely to occur. As a result, larger gallonage treatments and higher pumping rates are required to displace a given amount of sand into the formation.
2. The fluid loss of most crude oils is very high. Higher injection rates are required in order to accomplish the same fracture penetration obtained through the use of more viscous fluids.
3. Sand screen-outs or bridging frequently occurs when attempts are made to pump sand and crude oil through casing perforations.
4. Crude oils not native to the formation in which they are used may cause emulsion problems and difficult "clean-up."
5. A definite fire hazard exists when crude oils are handled in open tanks around pumping equipment.

Sand settling rates are much higher than those of the refined oil carrying agents. At formation temperatures the fluid loss of most crude oils is too high to be measured with standard equipment.

SAND

The exact function of the solids used during a frac treatment is somewhat controversial. Several theories have been proposed, namely, that:

1. The solid particles penetrate planes of weakness, propping them open after the carrying agent has been removed.
2. The particles act to scour or erode the walls of the passages through which they are displaced.

The solids used in a frac treatment are chosen on the basis of the following properties: particle size, shape, hardness, compression strength, permeability of a packed column, reaction with well fluid, availability, and economy. Silica sand that has been washed and screened appears to be the most practical material for this use. The most popular size is 20-40 mesh, which consists of sand grains having diameters from 0.015 to 0.030 in (0.4 to 0.8 mm).

The Humble Oil and Refining Co. has suggested the adoption of a visual roundness evaluation chart originally proposed by Krumbein.[1] This is shown in Fig. 1. Roundness is thus defined as the ratio of the average curvature of the several corners to the radius of curvature of the largest inscribed circle on the projected image of the sand grain.

The commonly used 20-40 mesh, round grain sand (see picture .6 on roundness chart, Fig. 1) has a packed permeability of 105 Darcys. In general, the larger the grain size, the greater the permeability, with angular shaped grains having a somewhat lower permeability than round grains of equal size. Field data indicate that a high degree of roundness is desirable in order to place more sand into a formation without bridging.

The concentration of sand carried in the frac fluid is governed by the equipment through which it must be pumped, the type of carrying agent, and the nature of the formation being treated. The quantities of sand and carrying agent should be carefully chosen when planning a frac treatment.

In general, the more sand displaced into the formation, the better the results will be. This holds true whether either the propping or scouring theory is applied. The maximum concentration of sand that can be handled by any particular carrying agent is dependent upon: (1) the agent's ability to support sand; (2) its fluid loss in relation to the permeability of the matrix; and (3) the anticipated injection rate.

Field experience has shown that the percentage of screen-outs has been reduced by the use of high injection rates. Another method of minimizing screen-outs has been to lower the fluid loss of the carrying agent, with respect to the formation. This is dependent upon the ability of the formation to accept the fluid being used as a carrying agent. Unfortunately, this latter factor is usually determinable only by trial and error.

The most practical approach to the problem of screen-outs is now indicated from field experience. The first step is the classification of formations into two groups: (1) those that will accept high rates of injection, and (2) those that will accept only low rates of injection, under the pressure limitations of well equipment. For the first group, high injection rates are in most cases sufficient to avoid screen-out difficulties. When treating formations which require low rates of injection, however, care must be taken to choose a carrying agent with excellent sand-supporting properties, in order to avoid the accumulation of high sand concentrations opposite the formation. Such an accumulation usually results in a complete shut-down, due to a fill-up of sand in the wellbore.

[1]References given at end of paper.

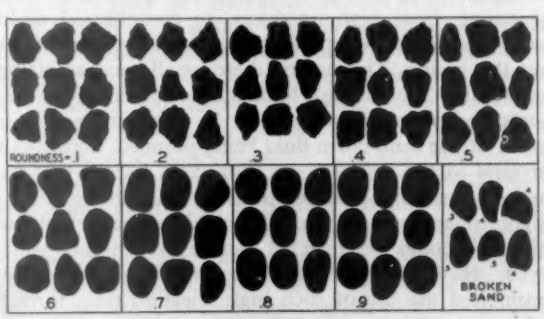

Fig. 1 — Roundness Chart for Sand.

In evaluating the sand-supporting properties of a carrying agent, the factor of temperature should not be overlooked. The majority of carrying agents, which depend upon viscosity for their sand-supporting ability, tend to thin down at elevated temperatures. Thus, the sand-suspending ability of the proposed carrying agent under conditions of bottom-hole temperature must be taken into consideration. In general, where temperatures exceeding 175° F are anticipated, and where injection rates are low due to pressure limitations of the well, it is necessary to use emulsion type carrying agents, designed for high temperature use.

EQUIPMENT

The development of frac methods of well stimulation has resulted in many changes in wellhead equipment, bottom-hole tools, pumping equipment, mixing equipment, and transporting equipment. Although at times the transition may have seemed slow, actually the change has taken place in record breaking time.

Pumping equipment has been advanced from units capable of pumping 40 gal/min at 5,000 psi, to units capable of pumping as high as 300 gal/min at 5,000 psi. These units are designed to operate for long periods of time at high pressures — up to 15,000 psi, whereas previously such pressures could be tolerated only for short intervals.

The changes in types of carrying agents employed have required the handling of highly inflammable fluids. Adequate safety precautions must definitely be made a part in the planning of any treatment. Thus far, the industry's record has been excellent, but there is still room for improvement. Specially designed fire fighting equipment is now made available on location in the form of improved extinguishers, coverings, and truck-mounted fire fighting equipment. The demand for more and better personnel protective equipment is constantly increasing. The increase in monetary loss and extent of personal injury has arisen sharply for each accident, making it essential that a cooperative and respectful attitude toward safety be prevalent among servicing personnel and personnel in charge of well equipment.

APPLICATION TECHNIQUES

A study of Permian Basin wells indicates that the two basic problems in applying various types of frac treatments are: (1) to inject the sand-laden fluid into the producing formation; and (2) to recover the carrying agent, while leaving the sand in place and the openings free from undesirable materials.

During early treatments, the accepted method of application employed the use of tubing, with several types of pack-off tools. These tools varied from single casing pack-off elements used primarily for protection of casing from high pressures, to complicated multi-pack-offs used to isolate various zones as well as protecting the casing. The use of these small treating strings (normally, 2-in tubing) limited the injection rates and consumed valuable horsepower in overcoming friction losses of the sand-laden fluid being pumped. Screen-outs of sand in the wellbore were always a hazard that had to be taken into consideration. It was believed that if higher injection rates could be obtained, larger volumes of sand could be injected before screen-outs would occur. However, the high pressures due to friction loss, prohibited the use of such high injection rates through tubing.

The first producer in the Permian Basin to use high injection rate techniques for injecting larger amounts of sand into the formation, was the Southern Production Co. Instead of applying the frac treatment through tubing, the materials were injected down the casing. Under these conditions, even though the injection rate was four times that normally used on frac treatments, the surface working pressure necessary to inject the sand-laden fluid was decreased by 50 per cent. These treatments showed that, not only was the mechanical efficiency of application improved, but the resulting production indicated that the effective increase in bottom-hole working pressures, the increased volume of materials injected, and the increased rate of injection were all beneficial to the well. As a result, these "down-casing" treatments have been extensively employed in the Permian Basin area with favorable results. On wells which contained bad casing, or had zones requiring isolation which made it necessary to inject the frac materials down the tubing, the use of larger diameter tubing (normally 3-in) was initiated by oil operators.

Field results have substantiated the fact that large volume treatments (10,000 gal or more) result in better "conditioning" of many reservoirs because:

1. Commercial producers have been obtained by large volume treatments in wells where smaller treatments failed.
2. Greater production increases have been secured with increases in the size of treatment.
3. Production declines have been slower as greater drainage area was obtained in the well.

Such higher gallonage treatments have been made possible by the use of higher injection rates during frac treatments. Such high injection rates also yield the following advantages: (1) deeper penetration of sand-laden fluids; (2) prevention of screen-outs or lock-ups at the wellbore; and (3) reduction of the effect of temperature changes on the physical properties of the carrying agent during the treatment.

It should not be inferred that frac treatments are a cure-all that eventually will replace other methods of well stimulation, such as acidizing. Some formations, especially those in a plugged condition, require an acid treatment preceding the frac treatment. Almost any zone will be benefitted by a spearhead of regular or mud acid. Such a pretreatment results in lowering injection pressures and dissolving materials that may cause restriction to flow.

Another controversial question is whether or not an overflush following a frac treatment is beneficial, and, if so, the amount of overflush which should be employed. It is believed that some overflush is beneficial because it:

1. Moves the sand back from the wellbore, to keep it from being produced.
2. Breaks emulsions that may have formed in the formation.
3. Thins refinery oil, when such has been used as a carrying agent.
4. Benefits the critical area when acid overflush is used in carbonate reservoirs. Carbon dioxide gas produced by the chemical reaction will tend to give the well initial life, reducing swab time. It is also believed that acid used for overflush will enter small "feeder" planes, further conditioning the reservoir for increased production.

Although the application of frac treatments has solved many well problems, it has also created some

TABLE 1 — RESULTS OF FRACTURING TREATMENTS IN THE PERMIAN BASIN

Well	Pay Zone	Pool	County	Well Data	Treatment Data	Results		Remarks
						Before	After	
A	Rustler (sandy lime)	Keystone Colby	Winkler	Open hole 882'—1050'	20,000 gal acid 5,000 gal gelled acid 2,500 lb sand	Pumped off in 8 min	10,000 BWPD	Fresh water well used for injection program. Six alternate slugs of acid and "frac" materials used during treatment.
B	Delaware (sand)	Tunstill	Loving	5-year-old well Nitro-shot 3299'—3328'	6,000 gal lease oil/water emulsion 9,000 lb sand Inj. rate—7 bbl/min	12 BOPD pumping	70 BOPD flowing	Test 17 days after treatment.
C	Yates (sand)	South Wickett	Ward	20-month-old well "frac" completion 2568'—2758'	9,000 gal refined oil 18,000 lb sand Inj. rate—12 bbl/min down casing	7 BOPD	518 BOPD potential 40 BOPD (after 8 mo.)	Originally completed with 2000 gal "frac" treatment for 35 BOPD.
D	Queen (sand)	Langlie-Mattix	Lea	8-year-old well Nitro (300 qts) 3410'—3587'	5,000 gal lease oil/water emulsion 10,000 lb sand Inj. rate—10 bbl/min down casing	3 BOPD	147 BOPD flowing through 27/64" choke	No cleanout necessary after treatment in shot hole.
E	San Andres (dolomite)	Wasson	Gaines	New well 10,000 gal acid completion 5002'—5140'	10,000 gal refined oil 10,000 lb sand Inj. rate—18 bbl/min down casing	500 BOPD 3000/1 GOR	1400 BOPD potential 400/1 GOR	Inside location in old pool. Experimental job, following acid with "frac" treatment.
F	Glorieta San Angelo (dolomite)	Howard-Glasscock	Howard	New well Open hole 2775'—2995'	1,000 gal acid 3,000 gal acid/oil emulsion 6,000 lb sand Inj. rate—5 bbl/min down casing	Show	88 BOPD after 14 days	Field extension—old pool. Surface working pressure—350 psi.
G	Clearfork (dolomitic lime)	TXL	Ector	2-year-old well 10,000 gal acid completion 5460'—5910'	8,000 gal acid/oil emulsion 24,000 lb sand Inj. rate—24 bbl/min down casing	19 BOPD	187 BOPD flowing	Test on 7th day following recovery of treating fluids. No difficulty encountered.
H	Spraberry (sand and shale)	Pembrook	Upton	New well Perforated 6,000 gal hydrocarbon gel completion 7000'—7050'	20,000 gal refined oil 30,000 lb sand down casing	50 BOPD	342 BOPD flowing 220 BOPD after 18 days	Retreatment, three days after original completion.
I	Cisco	Cisco	Scurry	2-year-old well 500 gal Mud Acid completion 6180'—6212'	6,000 gal lease oil/water emulsion 12,000 lb sand down tubing	7 BOPD	112 BOPD after 54 days	Treated below packer. 40-60 mesh sand used. Previous treatments in area, using 20-40 mesh sand, screened out.
J	Canyon (sand)	Pardue	Fisher	1½-year-old well Open hole Natural completion 4424'—4450'	250 gal Mud Acid 3,000 gal refined oil 1,800 lb sand Inj. rate—2 bbl/min down tubing	40 BOPD	118 BOPD through 12/64" choke after 5 days	In "frac" treatment of offset well, without Mud Acid, formation would not accept desired amount of sand.
K	Devonian (lime)	South Andrews	Andrews	3½-month-old well 6,000 gal acid completion 10,864'—11,059'	20,000 gal acid/kerosene emulsion 30,000 lb sand down casing	55 BOPD	310 BOPD potential	Deepest well treated down casing, to date.
L	Waddell (sand)	Abell	Pecos	New well Perforated 5516'—5542'	3,000 gal lease oil/water emulsion 3,000 lb sand 250 gal Mud Acid Inj. rate—3 bbl/min down tubing	Show	192 BOPD	Previous treatments in this section with other carrying agents resulted in slow "clean-ups."

new ones. One such problem which has been accentuated by frac work is that of controlling gas and water ratios.

In many cases, where relatively close orientation of water zones to the bottom of the wellbore exists, the use of special types of bottom-hole plugs has prevented increases in water production. One of the most effective procedures has been the use of a high concentration of sand in a very thick carrying liquid, spotted across the zone expected to contain planes of weakness leading to water. More recently, the introduction of oil and cement slurry squeezes has aided in this type of control by blocking off such water leading planes and diverting the frac materials into planes of weakness within the oil bearing zone.

FIELD RESULTS

A tabulation of a number of Permian Basin frac treatments is given in Table 1. This table includes well data, treatment data, and treatment results. These particular wells were chosen as being representative although the type materials and size of treatment are not necessarily recommended for these individual pools. The results are as reported from the field and are subject to correction. Some wells in these various formations responded better and others less favorably than these examples; however, the wells cited are fairly typical. Frac treatments have met with equal success in gas wells.

High surface pressures apparently are not necessary in order to obtain sustained production increases, as evidenced by a number of these case histories. One example was a San Andres well in the Howard-Glasscock Pool, with broken pay from 2,115 ft to 2,220 ft. The well, originally completed with acid in 1952, was retreated with 9,000 gal of refined oil containing 12,000 lb of sand, in May, 1954. Surface working pressure was 150 psi, at 20 bbl per minute, with the well going on vacuum when the pumps were shut down. Originally producing 2 BOPD, the well was still making 60 BOPD with some water 45 days after the treatment.

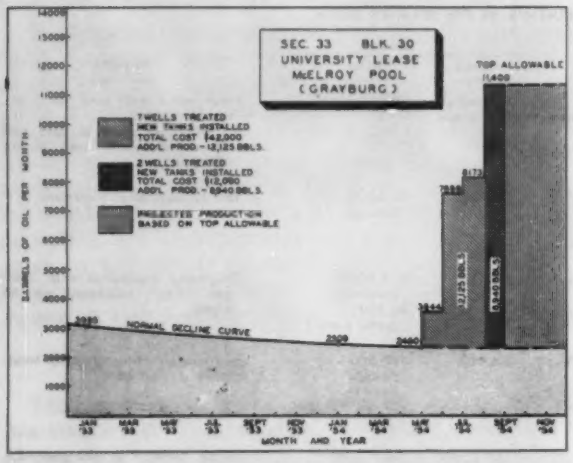

FIG. 2 — MONTHLY PRODUCTION ON LEASE, CONSISTING OF NINE WELLS

An example of how frac treatments have helped lease recovery in an old field is presented in graphic form in Fig. 2.

Each of the wells on this lease was treated with approximately 15,000 gal of refined oil and 30,000 lb of sand, at injection rates from 10 bbl per minute down 3-in tubing, to 20 bbl per minute down casing. To determine which method of treatment was to be used, a gauge log was run on each string of casing. Those indicated to be in good condition were treated down the casing.

Spinner surveys frequently are conducted when the desired results are not obtained following the frac treatment. These may reveal channeling, either around the bottom of the casing shoe or behind perforations. Correction steps then may be taken accordingly.

Also, spinner surveys will reveal what portion of the open hole was conditioned during the treatment. For example, spinner surveys were run on four wells in the Spraberry, before and after 20,000 gal refinery oil-sand treatments with both the upper and lower Spraberry open (separated by about 800 ft). In all four wells, the surveys revealed that only about 10 per cent of the spinner fluid entered the lower Spraberry. Although the wells responded favorably, it is indicated that further stimulation work, following decline, should be concentrated on the lower zone to obtain additional production.

SECONDARY RECOVERY

Many operators have been hesitant to perform frac treatments on wells in secondary recovery projects, for fear of early breakthrough of repressuring fluids resulting in by-passing of oil. It is conceivable that, under perfect flood conditions, the application of frac treatments might be a hindrance; however, such an ideal condition is rarely encountered. Many times when a flood has been established, it will be found that one or more of the injection wells failed to accept the requisite amount of water. It is frequently necessary to increase the system pressure, requiring the expenditure of excessive horsepower.

The treatment of water injection wells in waterflood projects is a sizeable operation that requires special carrying agents. Aqueous gels have been used in fracturing

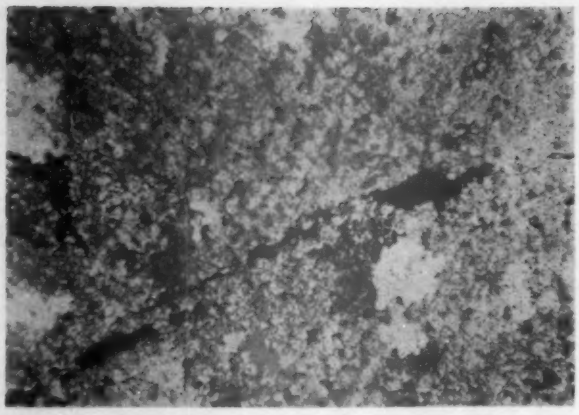

FIG. 3 — PHOTOMICROGRAPH OF CORE FROM GLORIETA FORMATION. OPEN FRACTURE (LOWER LEFT TO RIGHT CENTER) IN ANHYDRITIC DOLOMITE.

A number of these narrow, short fractures are present in the rock. Anhydrite crystals are white, however, some additional anhydrite crystals, such as the black area with dolomite inclusions at left center, are present but are not readily discernible, because they are in position of extinction. The dolomite grains range from microcrystalline to very fine. Intercrystalline porosity is poor to fair. (Magnification X 69.)

water input wells in Ward, Crockett, and Borden Counties. Most of these treatments have been successful in lowering the wellhead injection pressure, or increasing the volume of water that the well will accept at a given pressure. A study of over 30 injection wells showed that injection pressures were materially reduced following more than 80 per cent of the treatments. Not a single case of channeling or by-passing of oil has been found.

PETROGRAPHIC STUDIES

All wells are individuals, and as such, often respond differently to frac treatments. Recognizing that variations in physical and chemical makeup are probably at least partially responsible for such variations, a detailed study has been underway for the past several years of the physical and mineralogical structure of producing formations in the Permian Basin by W. A. Waldschmidt, geologist and petrographer. Microscopic examination of thin sections of rock was made from cores taken from producing wells. Not only the oil bearing zone, but sections above and below the pay were studied and photo-

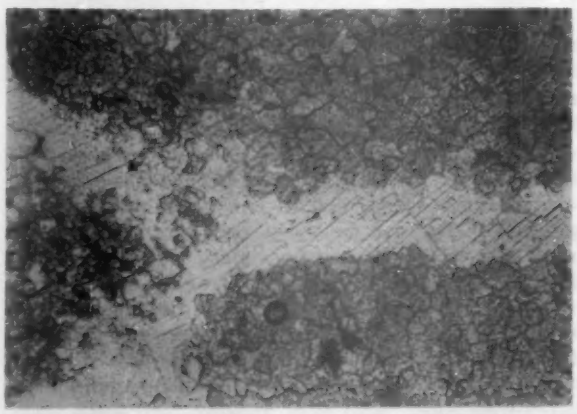

FIG. 4 — PHOTOMICROGRAPH OF CORE FROM SAN ANDRES FORMATION. BRANCHING ANHYDRITE FILLED FRACTURE IN MICROCRYSTALLINE DOLOMITE. ANHYDRITE IS THE WHITE MINERAL WITH CLEAVAGE; THE GRAY AREAS BEING DOLOMITE. (MAGNIFICATION X 69.)

graphed. From this study the fracture systems encountered were grouped according to their type (open, closed, filled, or partly filled), orientation, and grain size — both in the matrix and in the fractures.

Typical examples of Permian Basin formations, showing their crystal structure and planes of weakness, are shown in the accompanying photomicrographs, Figs. 3, 4, and 5. It was found that most of the formations in the Permian Basin were either fractured or possessed visible planes of weakness. These were not always strictly oriented in a horizontal or vertical plane, but in many cases were found to have random orientation with frequent inter-connections. It is evident that could such a fracture system be opened up and cleaned out, it should result in material benefit to the well, by providing improved drainage throughout the zone containing these fractures or planes of weakness.

Photographs of the face of the wellbore, made with a special bottom-hole camera, substantiate the evidence of cores with regards to the natural occurrence of such planes of weakness in Permian Basin formations. Typical pictures are shown in Fig. 6.

By recognizing the materials present in these planes of weakness, and planning the frac treatments accordingly, outstanding production increases have been obtained—in many cases much better than corresponding treatments planned solely on the basis of the physical and chemical properties of the matrix.

INTERPRETATION

Just what takes place in a formation during a frac treatment is not completely clear. At least two basic theories have been proposed to account for the mechanism of a frac treatment. The first theory is that fluids, penetrating the matrix under elevated pressures, rupture the rock horizontally, lifting the over-burden and resulting in an open, plane fracture. The injected sand holds the fracture open after the induced hydraulic pressure has been released.[2]

The second theory is that by the use of non-penetrating fluids, hydraulic pressure can be built up on the face of the wellbore, compressing the formation to a yield point where the rock splits longitudinally, producing a vertical fracture.[3]

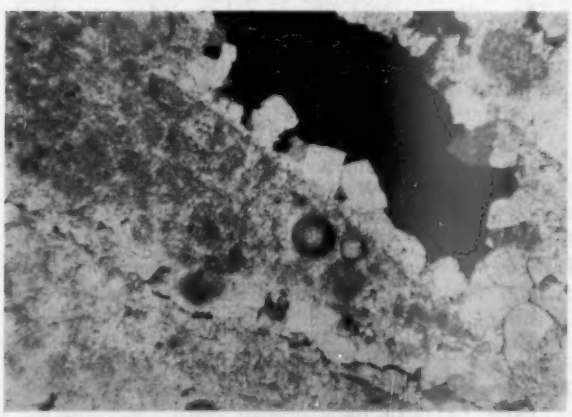

FIG. 5 — PHOTOMICROGRAPH OF CORE FROM PENNSYLVANIAN CORE. VUG (BLACK) LINED WITH CALCITE. Fracture extending from left to right at lower part of picture, connects five vugs, four of which are only slightly smaller than the one illustrated. The vug illustrated is connected to the fracture by intergranular porosity of the medium grained calcite in the lower right corner of the picture. (Magnification X 69.)

While these theories have merit, it is not believed that they completely explain observed field data. When frac treatments were conducted down tubing, the factor of friction loss made interpretation of surface working pressures difficult. With the introduction of down casing treatments, the observed pressures were relatively free of friction losses. Many times sand injection was accomplished at pressures far below those theoretically re-

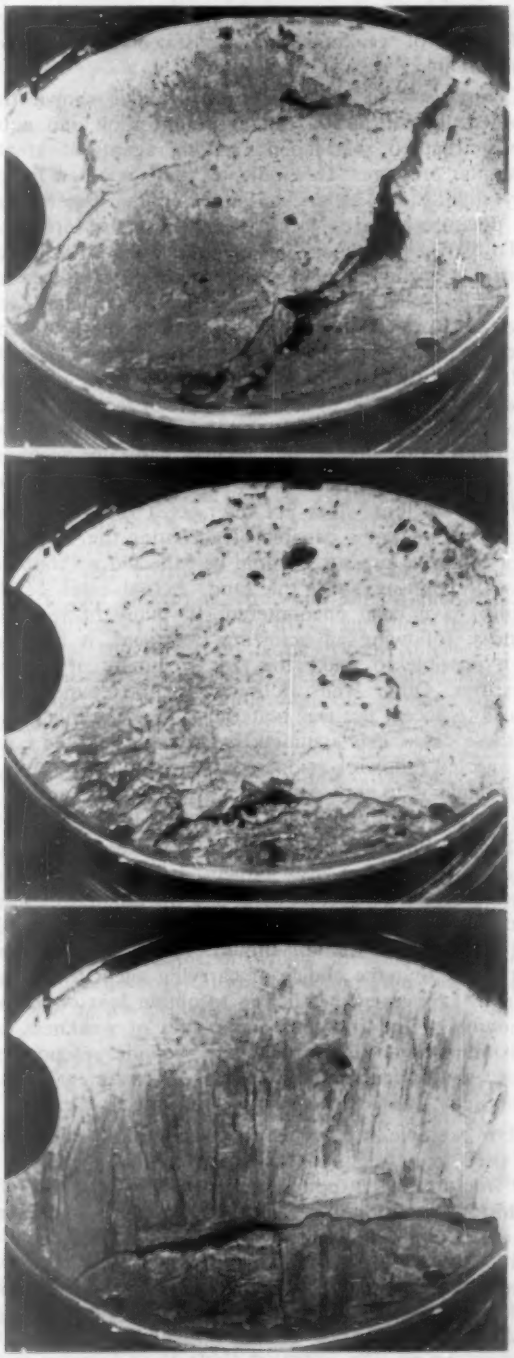

FIG. 6 — TYPICAL WELLBORE PHOTOGRAPHS (SIDEWALL) TAKEN WITH THE SPECIAL BOTTOM-HOLE CAMERA, SHOWING VARIOUS TYPES OF NATURALLY OCCURRING FRACTURES AND PLANES OF WEAKNESS IN THE SAN ANDRES FORMATION.

quired by either of these mechanisms. Accordingly, the authors favor a third theory, designed to explain some of these noted inconsistencies.

Bugbee[4] has suggested that during injection the frac fluid tends to follow the line of least resistance, penetrating fractures and naturally occurring planes of weakness in the formation—conditioning, extending, connecting, and retaining them in an open condition, so that fluid flow can be accomplished. The resulting drainage pattern may be completely random and will depend entirely on the naturally occurring fractures and planes of weakness characteristic of the formation being treated.

Comparison of observed pressures has shown that exposed formations of similar composition and equal depth accepted sand-laden carrying agents at greatly dissimilar pressures. This indicates that some new factor, only slightly considered, was influential in determining the pressure required to inject sand into the formation.

To clarify this theory, an exposed wellbore intersects naturally occurring planes of weakness, whether they be bedding planes, horizontal, vertical, or inclined fractures, or rock containing large vugular porosity separated by thin walls of low or non-permeable materials. Once the frac fluid has entered a plane of weakness, it will continue to follow the line of least resistance, flowing at random throughout the formation and following intersecting planes of weakness naturally occurring in the formation, as indicated by petrographic studies.

If the wellbore does not intersect a zone containing planes of weakness capable of accepting the frac fluid, then excessive pressures would be expected without successfully putting away the sand. Actual cases of this nature have been encountered. In many of these instances, following an acidizing treatment, it has then been possible to make the frac treatment at reduced pressures. Other wells, following acid treatment, still refuse to accept the frac materials. Applying this theory to these cases, it is assumed that where frac fluid could be injected following acidizing, the acid removed enough of the matrix to expose a plane or planes of weakness in the rock, adjacent but not connecting to the wellbore.

The multiplicity of planes of weakness within the zone to be treated thus largely determines the pressures that will be encountered, and the amount of solids that the formation will accept before lock-up or bridging will occur. Assuming this to be so, it then becomes important that the choice of carrying agent to be used in a frac treatment be such as to obtain maximum conditioning of the fractures and planes of weakness and maximum removal of products of secondary deposition. This would account for improved treatment results from jobs where this principle has been observed.

For example, a carrying agent containing acid would be used in a fractured formation containing calcite in the fractures, even though the matrix might be insoluble sandstone rock. Similarly, material encountered in some fractures might be adversely affected by aqueous gels, so that a refined oil carrying agent would yield improved results, even though the matrix might be acid soluble.

Many wells may be cited that further substantiate this theory:

EXAMPLE 1

1. Well drilled to 1,100 ft with 10 ft of open hole opposite oil saturated dolomitic lime.

2. Well pressured with aqueous fluid to 5,000 psi surface pressure and failed to accept fluid.

3. Well deepened 10 ft and accepted fluid at 3,600 psi breaking to 2,100 psi at injection rate of 1 bbl/min.

EXAMPLE 2

1. Well drilled to 11,000 ft with 30 ft of perforated section opposite Devonian lime.

2. Well accepted sand-laden acid/oil emulsion at 3,600 psi casing pressure, at a rate of 21 bbl/min.

EXAMPLE 3

1. Well drilled to 3,050 ft with 100 ft of open hole opposite dolomitic lime.

2. Well accepted sand-laden refined oil at 2,200 psi casing pressure at injection rate of 21 bbl/min.

EXAMPLE 4

1. Well drilled to 4,250 ft with 285 ft of open hole opposite dolomitic lime.

2. Well accepted sand-laden refined oil at 1,125 psi casing pressure at injection rate of 40 bbl/min.

CONCLUSIONS

1. All producing formations in the Permian Basin have responded favorably to frac treatments.

2. The results of such treatments have demonstrated the value of high injection rates and large treating volumes.

3. Mineral deposition within formation fractures, or planes of weakness, should be taken into consideration in selecting the proper carrying agent for a frac treatment.

4. Combination treatments are necessary in some formations in order to obtain maximum production increases.

5. Beneficial results have been obtained on many frac treatments without the use of high injection pressures.

6. Maximum sand concentrations should be used, consistent with the requirements of formations, carrying agents, and pumping equipment.

7. Properly engineered frac treatments have proven beneficial to water in-put wells in secondary recovery operations.

8. It is believed that during a frac treatment the treating materials follow naturally occurring fractures and planes of weakness in the formation and that the orientation of the resulting drainage pattern will depend on the original fracture pattern of the formation.

ACKNOWLEDGMENT

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CORROSION of OIL WELL CASING by EARTH CURRENTS

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ABSTRACT

In many areas casing failures can be directly related to electrical currents observed in the casings. It is the thesis of this paper that the observed casing currents are mainly due to electrochemical potentials of the type in evidence on spontaneous potential curves of electrical logs. The general nature of these potentials are discussed and an equivalent circuit is given for current and potential distributions around open holes. The casing forms a short circuit to these potentials and tends to average the effects of local cells. The case of casing corrosion opposite the Dakota water sands in the salt-mud area of Kansas is discussed and used as a qualitative illustration of the relation between SP's and casing currents. A method of quantitative derivation of casing current distribution from electric log SP curves, using linear transform theory, is described and results are compared with a measured current profile. The effects of hydrogen over-potentials at the cathodic portions of the pipe are considered and some laboratory data are given in support of conclusions regarding the overvoltages.

INTRODUCTION

To date an appreciable amount of work has been done on the measurement of oil well casing currents and on the correlation of the anodic portions of the current profiles with corrosive casing failures. Speculations on the origin of the casing currents have, however, remained rather vague; and although almost every plausible cause has been mentioned, there is to the writers' knowledge no clear-cut expose' on the details of the causes of the corrosive currents in the literature.

A study of current surveys and casing failures in the N.W. Burnett field, Ellis County, Kan., indicated the probability that concentration cell emf's between the Wellington salt section and the relatively fresh waters in the Dakota sands were a major cause of the corrosion currents. A more general concept evolved upon analysis of the severe corrosive conditions in the Pleistocene sands in the Ventura Avenue and San Miguelito fields in California. In this area no major variations in the salt content of the formation waters occur and yet large casing currents are observed. An explanation is found in the fact that the local spontaneous potentials which are set up due to concentration contrast between the drilling fluid and the connate water are short circuited when casing is set. The very conductive path through the casing increases the magnitude of the currents and has the tendency to average local sources over fairly large intervals. Current will flow between the sections that are predominently shaly and the sections that are mostly sandy. At the places where the current leaves the pipe, corrosive attack will occur.

This same phenomenon will be present wherever unprotected pipe is set through sections that show large SP kicks on the electric logs over reasonably thick intervals.

GENERAL NATURE OF THE SPONTANEOUS POTENTIALS

When a sequence of sedimentary rocks is penetrated by a drill hole filled with a mud which has a different salt concentration from that in the formation waters, various types of electrochemical potentials are established between the formations and different parts of the mud column. Opposite clean sand sections, a simple liquid-liquid junction potential will be observed; while opposite argillaceous formations, a membrane potential, often referred to as shale potential, will be established. The first quantitative analysis of these emf's in terms of liquid junction and membrane potentials is due to Wyllie.[1]

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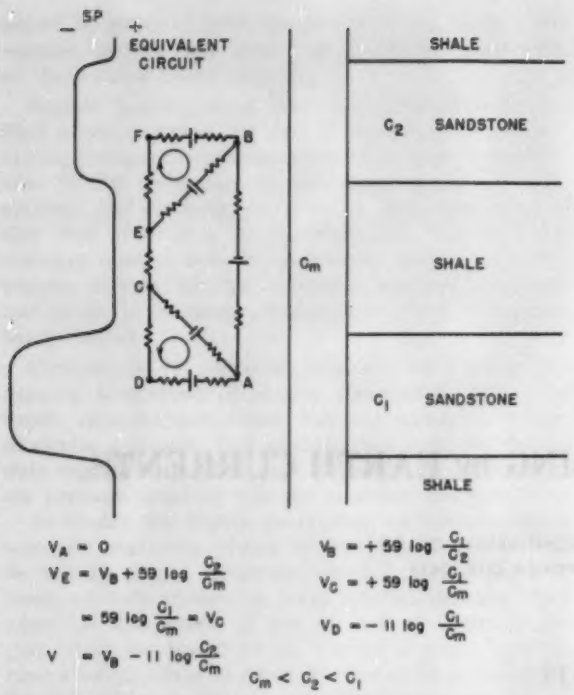

FIG. 1 — SP PROFILE AND EQUIVALENT CIRCUIT FOR FRESH MUD.

In the case of no current flow, the total difference in the potential of the mud column opposite a clean sand with respect to the mud column opposite an adjacent shale would be given by:

$$(SP)_s = 70.6 \log \frac{R_{mf}}{R_w} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (1)$$

where $(SP)_s$ is the total emf in case of no current flow and is referred to as the "static SP."

Since both the mud column and the surrounding formations are electrically conductive, the electrochemical emf's give rise to a sustained current flow. The spontaneous potential curve on electric logs is a measurement of the ohmic drops caused by these so called SP currents in the mud column. The general distribution of the potentials and the currents resulting from them was described in detail by Doll.[2]

The magnitude of the SP currents in the local cells at the formation boundaries depend on the static SP and on the total ohmic resistance in the circuit. Using Kirchoff's law, this may be expressed as:

$$(SP)_s = i_{sp} r_h + i_{sp} r_f \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (2)$$

where i_{sp} is the total SP current, r_h is the ohmic resistance it encounters in the hole, and r_f is the ohmic resistance it encounters in the formation. Equation 2 represents obviously an over-simplification of the three dimensional problem, since all of the current does not enter and leave the hole at the same distance from the boundary. It is, however, helpful in describing some of the characteristics of the SP currents. The factor r_h depends on the diameter of the drill hole and the resistivity of the mud, R_m, while r_f is a function of the formation thickness and the formation resistivity, R_t.

Fig. 1 shows a sedimentary section through two sandstone beds containing connate waters of different salinities separated by a shale bed. The section is penetrated by a drill hole containing a homogeneous mud column of salt concentration, C_m. The corresponding SP curve is given at the left of the figure. The center shows the equivalent circuit diagram in which the various liquid junction and shale potentials and the direction of current flow are indicated. The potential at A (within the bed containing water of concentration C_1) is arbitrarily taken as zero. We note that as long as the composition of the mud is homogeneous and the shales form perfect membranes, there will be a constant shale base line on the SP curve.

Changes in the salt concentration of the mud column will cause the shale base line to drift. Sandy and silty shales and shaly sands act as non-perfect membranes and result in potentials intermediate between those observed for the dense argillaceous shales and those found opposite clean sands.

STABILITY OF SP CELLS WITH TIME

The currents in the localized SP cells will always tend to diminish the concentration contrast between the formation water and the mud column. In the case of Fig. 1, the part of the current through the shale carries sodium ions from the formation water to the mud column. This excess of sodium ions in the mud is balanced by chlorine ions that reach the mud column through the sandstone. The flow of chlorine ions completes the other half of the current loop. Eventually the salt concentration in the mud column will equal that of the connate water of the immediately adjacent formations.

As the concentration contrast diminishes, the total emf in the cell decreases. The magnitude of the SP current and the rate of salt diffusion also become correspondingly smaller.

Using the theories described by Doll[2], we can make a rough estimate of the amount of time over which a typical SP cell will effectively operate in an open hole.

A calculation was made for the case of an 8-in hole filled with mud of 1 ohm-m resistivity (5,500 ppm) traversing a water sand of a thickness equal to 10-ft which contains connate water with a resistivity of 0.1 ohm-m (70,000 ppm) while the formation resistivity is 6 ohm-m.

We found that it would require approximately 160 years even if the current would remain at full strength to decrease the emf to one half of its original strength. It is apparent, therefore, that the diffusion of salt from the formations into the mud column of an open hole is too slow to materially effect the magnitude of the SP current cells.

During and immediately after the drilling of a well, thermal convection currents due to differences in temperature between the mud column and the formations may change the composition of the mud appreciably in front of very permeable formations.

Salt water influx from very high pressure sands is another factor that may in some cases effect equalization of the salt content of the mud column with that of the connate waters of the immediately adjacent formations.

If none of the above disturbances are too severe, then upon completion of the well and the setting of the casing, we shall find a fairly homogeneous mud column above the cement top in the annular space between the pipe and the formations. The electrochemical potentials will remain active in the same way as described for the open hole. The magnitude and distribution of the currents will, however, be changed appreciably by the presence of the highly conductive pipe.

SP CURRENTS IN THE PRESENCE OF CASING

An unprotected casing string not covered by cement or other insulating material forms a very conductive path for the SP currents. The resistance to current flow in the hole, r_h, will be drastically reduced and most of the ohmic drop in the SP current cell will now take place in the formations. In Equation 2, r_f, is now much larger than r_h. Due to the reduction in total resistance of the circuit, the current strength, i_{sp}, will of course be increased. In the hole essentially all of the current will follow the casing while a very small fraction will travel through the annular space filled with mud.

The most pronounced influence of the presence of the pipe on the distribution of the SP currents will be a very strong averaging of the effects of the local cells. This phenomenon is similar in character to that observed on electric logs when the ratio of formation resistivity to mud resistivity becomes very large, but its magnitude will be larger than that of even the most extreme cases witnessed on logs.

This averaging or smearing-out and consequent superposition of the local effects makes it difficult to visually estimate from the electric log SP curve where the most serious changes in current density in the pipe will occur. Except for very simple situations, one has to resort to fairly elaborate mathematical treatment to predict the distribution of the casing current from the open hole SP log.

QUALITATIVE FIELD EXAMPLE

The outside casing corrosion problem in many parts of the salt mud district of Western Kansas presents a fairly simple situation which permits qualitative treatment.

The high salinity of the mud in this area is caused by the fact that the wells penetrate the Wellington salt section. Rock salt will dissolve in the mud and change most of the mud column into a saturated salt solution. Even when fresh mud is spotted at the bottom of the well for electric logging purposes prior to completion, the mud column will rapidly become completely salt saturated in the annular space above the cement top, after casing has been set.

Fig. 2 shows a typical stratigraphic column taken from a well in the N.W. Burnett Pool, Ellis County, Kan. Since before electric logging fresh mud was spotted in all wells in this field, no SP curves are available that are representative for the equilibrium situation which will be reached shortly after casing is set. For this reason only a generalized salt-mud SP curve is given for the upper section of the hole. The Lakota and Dakota water sands, which have relatively fresh connate water (50,000 ppm) compared to the salt saturated mud column, give positive SP deflections.

The right hand side of Fig. 2 shows a casing current profile measured in one of the wells in the N.W. Burnett field. In order to find the corresponding potential distribution in the pipe, we have to integrate the current profile by determining the area under the curve. The result of this is shown under the heading "Potential profile after casing (amplified)."

We see that this potential distribution in the pipe resembles closely an averaged out version of the SP curve.

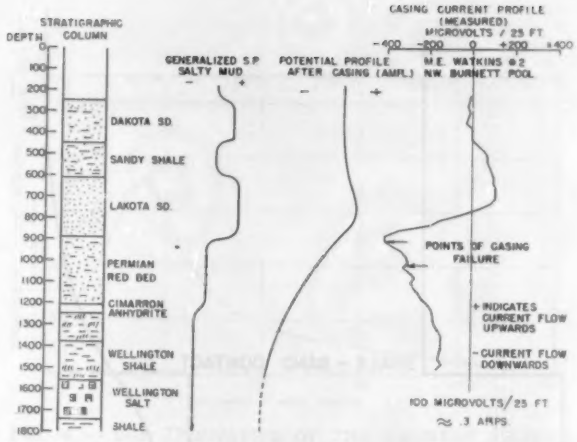

FIG. 2 — ON THE LEFT IS A TYPICAL STRATIGRAPHIC COLUMN AND, RIGHT, A CASING CURRENT PROFILE, BOTH OBTAINED IN WELLS IN THE N. W. BURNETT FIELD.

QUANTITATIVE APPROACH TO PREDICTION OF CURRENT PROFILES

In order to estimate the current and potential distributions in the casing due to the electrochemical emf's at formation boundaries, we may regard the hole with the casing string as a hole filled with an extremely conductive drilling fluid of resistivity R_{ma}. For a given casing weight and a given hole size, R_{ma} can be calculated by comparing the electrical resistance of 1 ft of casing with that of 1 ft of open hole filled with the hypothetical drilling fluid. If R_{ma} is expressed in ohm-meters, the latter is given by $\frac{12 \times 4}{.0254\ \pi\ d^2} \cdot R_{ma} = \frac{600}{d^2} \cdot R_{ma}$ ohms where d is the diameter of the hole in inches.

The potential distribution along the axis of a hole filled with fluid of resistivity R_{ma} can be calculated by the methods outlined by Doll.[2]

The equation given by Doll* for the distribution of the potential, $W(z)$, along the axis of the hole due to a single sand-shale boundary is:

$$W(z) = W_o \left[1 + \frac{z}{(1+z^2)^{1/2}} - \frac{2}{\pi} \int_0^\infty A(p,a)\ I_1(p) \sin pz\ dp \right] \quad (3)$$

with: $a = \frac{R_t}{R_m} - 1$ and: $A(p,a) = \frac{apK_0(p)\ K_1(p)}{1 + apK_0(p)\ I_1(p)}$

W_o = one half of the static SP change at the boundary
z = vertical distance along the axis of the hole
R_t = formation resistivity
R_m = resistivity of the drilling fluid
I_1 = modified Bessell function of first kind and first order
K_o = modified Bessell function of second kind and zero order
K_1 = modified Bessell function of second kind and first order

*This equation appeared only in the appendix to Doll's paper which was included with the AIME preprint. In the final publication, the appendix was omitted.

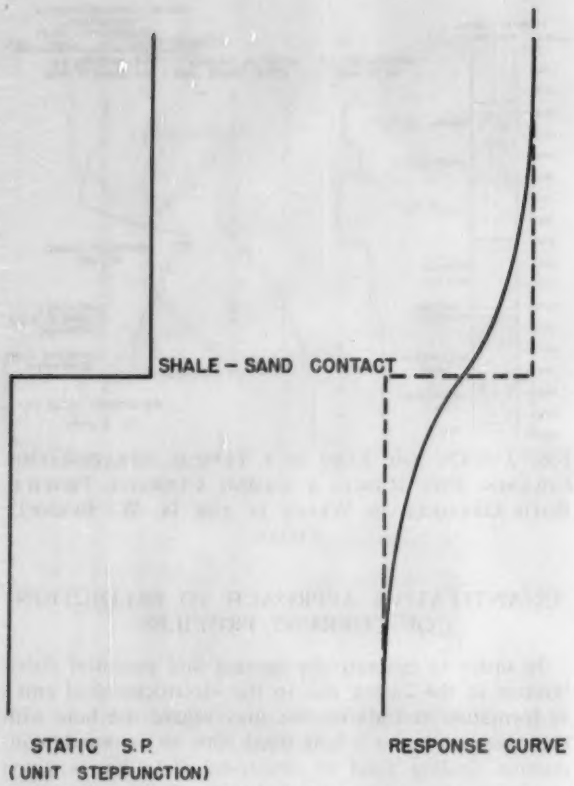

FIG. 3 — A GENERALIZED POTENTIAL DISTRIBUTION DUE TO A SINGLE ABRUPT CHANGE IN STATIC SP AT A SAND-SHALE BOUNDARY FOR THE CASE OF A RELATIVELY HIGH VALUE OF R_t/R_m.

Fig. 3 shows a generalized potential distribution due to a single abrupt change in static SP at a sand-shale boundary for the case of a relatively high value of R_t/R_m.

To find a typical value of R_t/R_{ms}, let us consider a 7-in 23-lb casing in a 10-in diameter hole traversing formations of average resistivity of 5 ohm-m. The resistance per foot of the casing will be approximately 10^{-5} ohm, so that:

$$\frac{600}{d^2} \cdot R_{ms} = 10^{-5} \quad \text{or} \quad R_{ms} = 1.67 \times 10^{-4}$$

and $$R_t/R_{ms} = 3 \times 10^6$$

At such high values of R_t/R_{ms}, the potentials due to sequences of layered formations will be averaged over large distances and the prediction of the amount of current flowing in the pipe at any particular point becomes fairly complicated.

A powerful tool for the solution of this type of problem is found in linear transform theory* as applied to communication systems.

We can regard the SP curve in the open hole before casing is set as a continuous function of depth [SP = $f_i(z)$] and consider an identical function of time $f_i(t)$ as the input to an electrical network, which distorts the input function in the same manner as the presence of casing effects the distribution of the spontaneous potentials. If we can find the response of such system to a simple input function such as a unit step function, it is then possible to calculate the response of the system to an arbitrary input function. The potential distribution along the pipe due to an abrupt change in static SP at the boundary of two infinitely thick beds as calculated from Doll's equation may be regarded as the response to a unit step function.

The following derivation shows the details of this application of linear transform theory:

The function SP = $f_i(z)$ may be expressed by the Fourier integral theorem as:

$$f_i(z) = \sqrt{\frac{1}{2\pi}} \int_{-\infty}^{\infty} e^{jux}\, g_i(u)\, du \quad . \quad . \quad . \quad (4)$$

where $g_i(u) = \sqrt{\frac{1}{2\pi}} \int_{-\infty}^{\infty} e^{-jux}\, f_i(x)\, dx$

is the Fourier transform of $f_i(z)$. Similarly for the response or output of our system (the potential distribution after casing is set), we may write:

$$f_r(z) = \sqrt{\frac{1}{2\pi}} \int_{-\infty}^{\infty} e^{jux}\, g_r(u)\, du \quad . \quad . \quad . \quad (5)$$

Let us define the distortion factor $D(u)$ as:

$$D(u) = \frac{g_r(u)}{g_i(u)} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (6)$$

and introduce the response function $R(z)$ as given by:

$$R(z) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\infty} D(u)\, e^{jux}\, du \quad . \quad . \quad . \quad (7)$$

so that $D(u)$ is the Fourier transform of R. We then can write:

$$D(u) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\infty} R(w) e^{-juw}\, dw \quad . \quad . \quad . \quad . \quad (8)$$

If we set $w = z\text{-}y$ and combine Equation 12 with the expression for $g_i(u)$ in Equation 8, we obtain after rearrangement:

$$g_r(u) = g_i(u)\, D(u) =$$

$$\frac{1}{2\pi} \int_{-\infty}^{\infty} e^{-jux} \int_{-\infty}^{\infty} f_i(y)\, R(z\text{-}y)\, dy\, dz \quad . \quad . \quad . \quad . \quad (9)$$

Also we have for the Fourier transform of $f_r(z)$:

$$g_r(u) = g_i(u)\, D(u) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\infty} e^{-jux}\, f_r(z)\, dz \quad . \quad (10)$$

Since Equations 9 and 10 both express $g_r(u)$ as a Fourier transform and the inverse operation of taking a Fourier transform is a unitary transformation we have:

$$f_r(z) = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\infty} f_i(y)\, R(z\text{-}y)\, dy \quad . \quad . \quad (11)$$

This is known as the superposition theorem or Duhamel's integral and may be interpreted as stating that the output function $f_r(z)$ at any value of z equals the integral of the responses at z due to all elements dy of the input function $f_i(y)$ taken over the entire range from $-\infty$ to $+\infty$.

$R(z)$ can be found from the response $f_r^*(z)$ of the system to a unit step function. The latter is given by:

$f_i(z) = 1$ for $z > 0$, and $f_i(z) = 0$ for $z \leq 0$.

For this input Equation 11 gives:

$$f_r^*(z) = \frac{1}{\sqrt{2\pi}} \int_0^{\infty} R(z\text{-}y)\, dy$$

so that $$R(z) = \frac{d\, f_r^*(z)}{dz} \cdot \sqrt{2\pi} \quad . \quad . \quad . \quad . \quad . \quad . \quad (12)$$

*The first examples of the application of linear transform theory to well logging problems are due to R. G. Piety of the Phillips Petroleum Co.

Equations 11 and 12 can be used to compute the potential distribution in the casing, if the initial open hole potential distribution $f_i(z)$ is given. The response of our system to a unit step function input is given by Equation 3 with $W(z) = f_r^*(z)$.

The application of the linear transform theory to our problem in the above fashion assumes that $f_r^*(z)$ is unique for the entire system, which in turn implies that R_t/R_{ms} is a constant. For our purposes this approximation will be sufficiently close for most cases.

Equation 11 gives us the potential distribution $f_r(z)$ along the casing. In practice we are more interested in the currents in the pipe than in the potential distribution, so that we want to compute the derivative of $f_r(z)$ with respect to z. Differentiating Equation 11 gives:

$$\frac{d f_r(z)}{dz} = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{\infty} f_i(y)\, R'(z-y)\, dy \quad . \quad (13)$$

where $R'(z) = \dfrac{d^2 f_r^*(z)}{dz^2} \cdot \sqrt{2\pi}$

The latter quantity is found by differentiating Equation 3 twice with respect to z which gives:

$$\frac{1}{\sqrt{2\pi}} R'(z) = \frac{d^2 f_r(z)}{dz^2} = W_o \frac{-3z}{(1+z^2)^{5/2}} + \frac{2}{\pi} \int_0^{\infty} p^2\, A(p,a)\, I_i(p) \sin pz\, dp \quad . \quad . \quad . \quad . \quad . \quad (14)$$

Fig. 4 shows the derivative of the current profile corresponding to a unit step function input of potential at a single sand-shale boundary, $R'(z)$, for a value of R_t/R_{ms} of 3×10^6 in a 10-in hole as calculated from Equation 14.

Once $R'(z)$ has been found for all values of z, Equation 13 gives us $\dfrac{d f_r(z)}{dz}$ which is proportional to the current in the pipe at any given depth z. Equation 13 states that in order to obtain the value of the current at a particular depth, say z_1, we have to multiply each point of the entire input function $f_i(y)$ with corresponding points $R'(z_1\text{-}y)$ for all values of y from $-\infty$ to $+\infty$ and then integrate the product. As practical limits for this process, one would choose those values of y where $R'(z\text{-}y)$ becomes negligibly small.

We note, however, from Fig. 4 that $R'(z)$ does not become negligible below values of z/r smaller than 3,000. In a 10-in hole, this means that the integration of Equation 13 must be carried out over a range of at least 1,250 ft on each side of the depth value for which the current response is being calculated. Near the end points of the unprotected casing strings, the contributions of part of the input function are distorted to an appreciable extent and our calculations have to be corrected accordingly.

CORRECTIONS FOR END EFFECTS

Cement Top and Surface Pipe Cement

The parts of the hole where the formations are separated from the casing by a cement sheath do not receive any signals. Also since the cement is relatively nonconductive, there are no return paths through the corresponding sections and the casing current due to SP potentials must be zero.

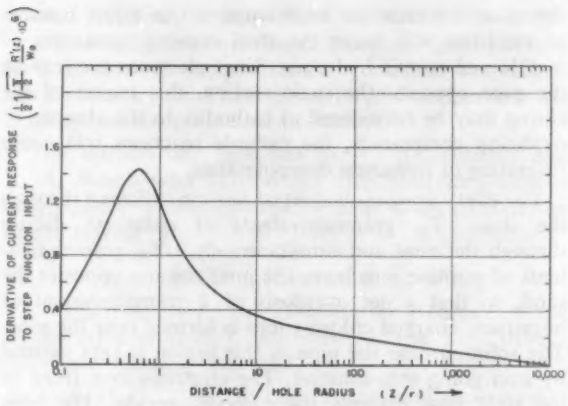

FIG. 4 — THE DERIVATIVE OF THE CURRENT PROFILE CORRESPONDING TO A UNIT STEP FUNCTION INPUT OF POTENTIAL AT A SINGLE SAND-SHALE BOUNDARY, $R'(z)$, FOR A VALUE OF R_t/R_{ms} OF 3×10^6 IN A 10-IN HOLE AS CALCULATED FROM EQUATION 14.

If we apply Equation 13 to the portions near the cement sheaths, the sections protected by the sheaths will not contribute to the integral; and since the $R'(z)$ is a symmetrical and odd function, the value of the calculated response will steadily increase as we near the ends of the open interval. This end effect is similar to that of a current source located at each end of the open interval. To correct for the end effects, we must subtract the effects of these apparent current sources from our calculated curve. The effect of a current source $\bar{c}(z_o)$ located at depth z_o (casing shoe of surface pipe) will to a first approximation be $\bar{c}(z_o)\, e^{-(z-z_o)\alpha}$. A value of $\alpha = 1.2 \times 10^{-3}$ is found by graphically approximating $\dfrac{dW}{dz}$ which in turn can be obtained as the area under the curve of Fig. 4. The effect of the source $\bar{c}(z_1)$ located at z_1 (top of oil string cement) is similarily approximated by $\bar{c}(z_1)\, e^{+(z-z_1)\alpha}$. Actually the amounts of current calculated at z_o and z_1 are both combinations of the effects of $\bar{c}(z_o)$ and $\bar{c}(z_1)$. We must therefore make a correction consisting of a linear combination of the terms $\bar{c}(z_o)\, e^{-(z-z_o)\alpha}$ etc. such that the corrected c_x vanishes at both ends. This is done by using $\sinh \alpha z = \frac{1}{2}(e^{\alpha z} - e^{-\alpha z})$ and making the corrected current of the form:

$$c(z)_{corr} = c(z) - c(z_1) \frac{\sinh \alpha (z\text{-}z_o)}{\sinh \alpha (z_1\text{-}z_o)} - c(z_o) \frac{\sinh \alpha (z_1\text{-}z)}{\sinh \alpha (z_1\text{-}z_o)} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (15)$$

POLARIZATION EFFECTS

The effectiveness with which the spontaneous potentials are able to produce sustained current flow in the pipe will to a large extent be dependent on the polarization produced by the products of the electrode processes.

In order to have a clear picture of the type of transport occurring in the SP cells shorted by casing, we might consider the simple case of a pipe set through a section containing a single boundary between a very thick shale and an equally thick salt water sand (see Fig. 5).

If, as in the usual case, the formation water is more saline than the mud, sodium ions will diffuse through

the shale towards the mud annulus. An equal number of electrons will leave the steel causing formation of NaOH and atomic hydrogen. Since electrons are leaving the pipe opposite the shale section, this region of the casing may be considered as cathodic. In the absence of oxidizing compounds, the cathode reactions will cause formation of hydrogen overpotentials.

For every gramequivalent of sodium diffusing through the shale, T_{Cl} gramequivalents of chlorine* diffuse through the sand and simultaneously $1\text{-}T_{Cl}$ gramequivalents of positive ions leave the mud column opposite the sand, so that a net overdosis of 1 gramequivalent of negatively charged chlorine ions is formed near the pipe. The solution near the pipe in this region is kept neutral by iron going into solution. The electrons thus freed in the steel flow towards the cathodic region. The area opposite the water sand where iron is going into solution can be termed the anodic region of the pipe and is of course the locus of the corrosive attack.

If the formation waters are aerobic brines, no hydrogen overvoltages will be formed at the cathode. On the other hand, the early formation of rust on the pipe may cause an obstruction to the diffusion of iron away from the anode. This would tend to cause a concentration overpotential which might counteract to some extent the operative emf. In general, however, the SP cell would be expected to operate fairly effectively and corrosion should be severe. Under anaerobic conditions, there should normally be no hindrance to the formation of hydrogen overpotentials at the cathode. Typical current densities at the cathodic areas of the pipe as measured by casing current surveys are of the order of 10^{-5} amp/sq cm. At these low current densities, the hydrogen overpotentials are only a small fraction of their maximum value for iron in NaOH which is around 80 mv. The overpotentials are therefore not expected to be sufficiently large to effect the operation of the SP cell seriously. They will, however, have the tendency to decrease the total currents and diminish the corrosive attack somewhat. If sulfate reducing bacteria are present, the cathodic hydrogen may be continuously removed and the cell will operate in full strength. For this reason the SP theory of corrosion and the theories of corrosion under anaerobic conditions due to presence of sulfate reducing bacteria are not mutually contradictory.

If hydrogen sulfide is present, insoluble iron sulfide scale will form a diffusion barrier at the anodes and corrosion is expected to be retarded.

*T_{Cl} denotes the transference number of chlorine in NaCl.

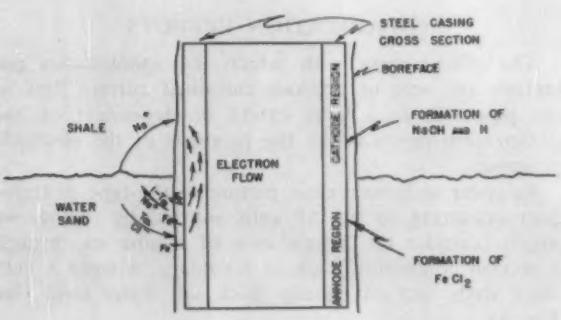

FIG. 5 — CASING CORROSION BY ELECTROCHEMICAL SP CELL.

The presence of carbon dioxide will usually cause formation of insoluble carbonates at the cathodes which also should have a retarding effect on the corrosion.

EXPERIMENTAL DATA

A few experimental checks were made on the speculations regarding the influence of polarization on the behavior of SP corrosion cells. To this end a cell was made by contacting a 6-in long core of black shale with NaCl solutions of 0.5 N and 0.05 N respectively at opposite sides. Submersed in each solution was a casing corrosion coupon and the two coupons were connected through a standard resistor. The emf across the cell without current flow was measured as approximately 50 mv. The solutions were at equilibrium with the atmosphere (oxygen content 8 ppm). The internal resistance of the cell as measured between the electrodes was 1,100 ohms, while the standard resistor connecting the electrodes was 25 ohms. A sustained current was obtained through the system during the entire length of the experiment which lasted four weeks. The average value of the current at the end of the experiment was 44 microamps. With the full electrochemical emf applied to the cell a current of $\frac{50 \times 10^{-3}}{1{,}125} = 44.5$ microamps would be expected. These measurements show that no measurable hydrogen overvoltage was present under the aerobic conditions of the experiment.

A short experiment was made under anaerobic conditions in the same cell as described above.

Most of the oxygen was removed from the salt solutions by scrubbing with oxygen free nitrogen. Before the casing coupon electrodes were connected, 20 ppm of sodium hydrosulfite was added to each solution.

Under these conditions an overvoltage of -22.4 mv was found at a current density of $.62 \times 10^{-5}$ amps/sq cm and -29.1 mv at a current density of $.76 \times 10^{-5}$ amps/sq cm while the original SP voltage was 50 mv. To a first approximation the overvoltage appears proportional to the current density and therefore has the effect of a resistance in the line of current flow.

Since the surface area of the pipe is large and the current path through the formations is fairly long, this added resistance will have a markedly smaller effect than in the case of electrolytic corrosion in microcells, caused by dissimilarity in metal composition between bands or grains of the metal. In the latter case, the apparent resistance of the overvoltage will be very large compared with the ohmic resistance of the electrolyte solution contacting the metal.

Nevertheless, the above measurement shows that in anaerobic systems the hydrogen overpotentials at the cathode can counteract the driving emf's to an appreciable extent at the cathodic areas. This will cause nonlinearity in the response of the system to impressed voltages and may be largely responsible for the type of anomalies observed.

CONCLUSIONS

SP currents, such as evidenced on electric logs, form a plausible cause for many cases of external casing corrosion, where the corrosion cannot be explained by metallurgical anomalies in the pipe.

Current patterns predicted from electric log SP curves

check closely with measured current profiles in the salt mud area of Kansas.

A mathematical treatment, based on linear transform theory, has been worked out for the derivation of current profiles from the SP curve in complex cases of interlaminated formations. Limitations of the theoretical procedure are indicated.

The theory and data presented in this paper indicate that in many fields outside casing corrosion may be mitigated by removing the open hole spontaneous potentials before casing is set. Where salt sections are not present or can be cemented off, this can be achieved by making the salinity of the mud equal to the average salinity of the formation waters in the interval between the surface pipe shoe and the oil string cement top.

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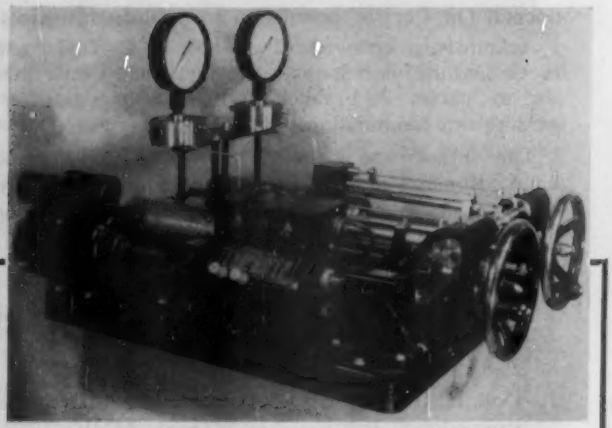

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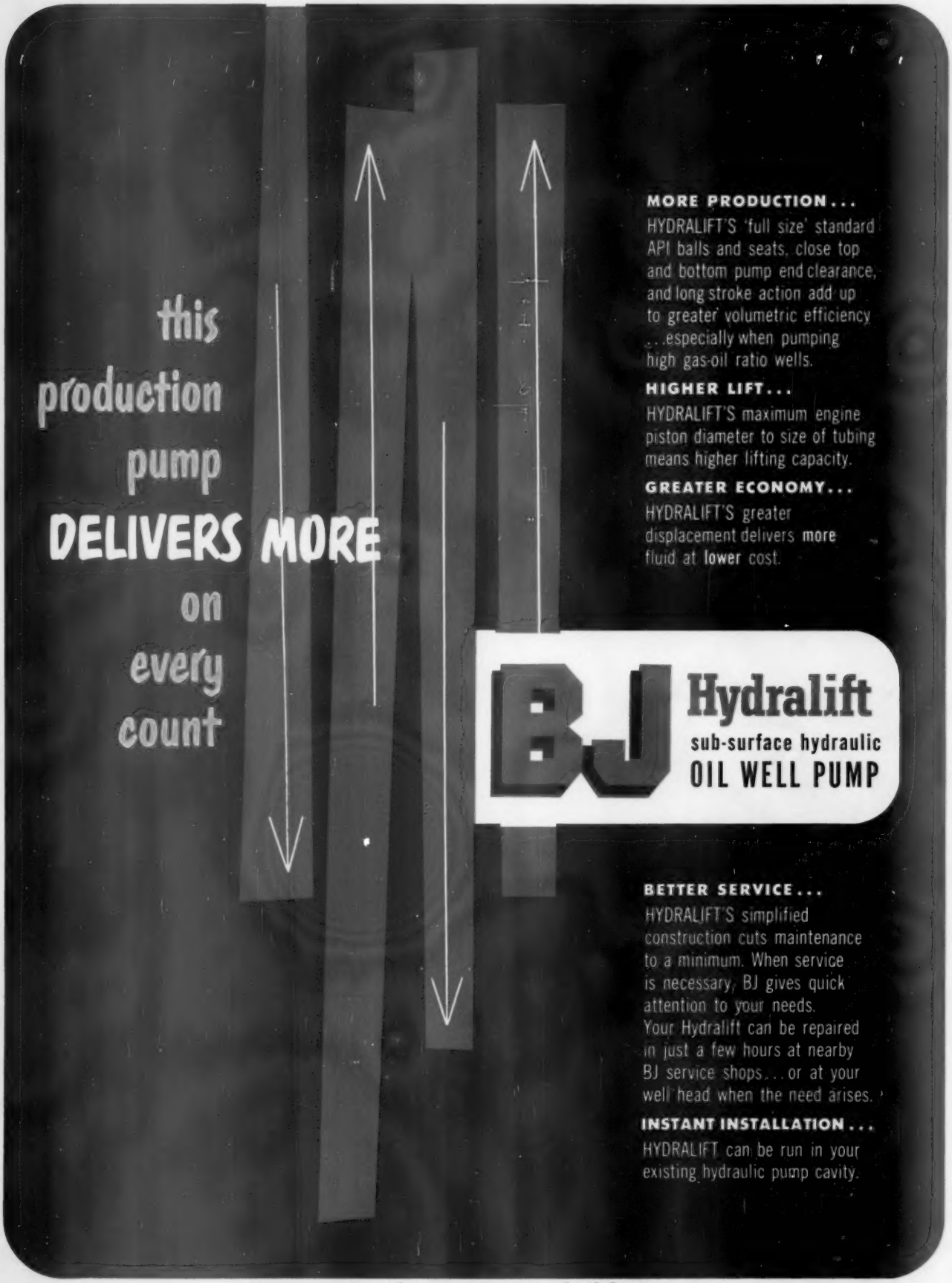
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